ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

TECHNICAL ANALYSIS REPORT
for
Air Quality Control Minor Permit No. AQ0214MSS01

Nushagak Cooperative, Inc.
Dillingham Power Plant

PLANTWIDE APPLICABILITY LIMITATIONS (PALS) FOR NO_X, CO, PM, AND SO_2

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Abbreviations/Acronyms

AAC ....Alaska Administrative Code
ADEC ....Alaska Department of Environmental Conservation
AS ....Alaska Statutes
ASTM ....American Society of Testing and Materials
BACT ....Best Available Control Technology
C.F.R. ....Code of Federal Regulations
EPA ....Environmental Protection Agency
EU ....Emission Unit
PSD ....Prevention of Significant Deterioration
PTE ....Potential to Emit
RA ....Relative Accuracy
RM ....Reference Method
SN ....Serial Number

Units and Measures

bhp ....brake horsepower or boiler horsepower
gr./dscf ....grains per dry standard cubic feet (1 pound = 7,000 grains)
dscf ....dry standard cubic foot
gph ....gallons per hour
kW ....kilowatts
kW-e ....kilowatts electric[1]
kWh ....kilowatt-hour
lbs ....pounds
mmBtu ....million British Thermal Units
ppm ....parts per million
ppmv ....parts per million by volume
tph ....tons per hour
TPY ....tons per year
wt% ....weight percent
MHz ....Mega Hertz

Pollutants

CO ....Carbon Monoxide
HAPS ....Hazardous Air Pollutants
H_2S ....Hydrogen Sulfide
NO_X ....Oxides of Nitrogen
NO_2 ....Nitrogen Dioxide
NO ....Nitric Oxide
PM-10 ....Particulate Matter with an aerodynamic diameter less than 10 microns
SO_2 ....Sulfur Dioxide
VOC ....Volatile Organic Compound

[1] kW-e refers to rated generator electrical output rather than engine output

1. INTRODUCTION

Nushagak Cooperative, Inc. (Permittee) owns and operates the Dillingham Power Plant in Dillingham, Alaska. The Dillingham Power Plant is located in southwestern Alaska approximately 327 miles southwest of Anchorage, Alaska. Dillingham is located at the extreme northern end of Nushagak Bay in northern Bristol Bay, at the confluence of the Wood and Nushagak Rivers. The Dillingham Power Plant provides electric power to the City of Dillingham, Alaska, and surrounding communities. The communities are not linked to any regional power grid and therefore rely solely upon the Dillingham Power Plant to meet all their electric power requirements.

2. BACKGROUND

The Dillingham Power Plant is classified under the Standard Industrial Classification (SIC) code as 4931 Electric and Other Services Combined. The Dillingham Power Plant is classified as a Prevention of Significant Deterioration (PSD) major source, for emitting more than 250 tons per year of oxides of nitrogen (NO_X). The Dillingham Power Plant consists of diesel-fired electric generators with a total generating capacity of 6,385 kilowatts electric (kW-e).

2.1. Permitting History

The Dillingham Power Plant is currently permitted under Construction Permit No. 0025-AC003 Revision 3, issued August 25, 2004 which contains restrictions to limit the stationary sources power generation by individual emission unit or groups of emission units. The permit also contains specific conditions to protect ambient air quality. The requested permitting action contains an ambient demonstration for changing these conditions.

In this permitting action the Department is carrying forward all relevant permit conditions in to the new minor permit and rescinding Construction Permit 0025-AC003, Revision 3, issued August 25, 2004.

3. PROJECT DESCRIPTION

The Permittee is requesting to revise Construction Permit No. 0025-AC003, revision 3 to revise existing ambient air quality protection restrictions. Existing power generation limits will be replaced with plantwide applicability limitations (PALs) for NO_X, sulfur dioxide (SO_2), particulate matter less than 10 microns in aerodynamic diameter (PM-10) and carbon monoxide (CO). The Permittee will monitor compliance with the requested PAL limits by obtaining site specific emission factors for each of the emission units, monitoring the power generation, fuel consumption, and fuel sulfur content. The Permittee will calculate the monthly and rolling 12-month emissions before the end of the 30^{th} day after the conclusion of the month being calculated. This shall be accomplished for each full and partial month during the effective period of the PAL. This shall be accomplished until all emissions emitted during the effective period of each PAL have been calculated for showing compliance with each PAL.

The requested minor permit changes and the newly established PAL emission limits will be rolled in to the Operating Permit. This will be accomplished as part of the Operating Permit renewal process, and the Operating Permit will be issued shortly after the minor permit.

This minor permit is classified under 18 AAC 50.508(3)[2] for the PAL and 18 AAC 50.508(6) for the changes to the Title I terms and conditions being modified before the effective dates of the four PALs. The project has an increase in emissions greater than the thresholds contained in 18 AAC 50.502(c)(3)(A), however this permit is not classified under 18 AAC 50.502(c)(3)(A) because under 18 AAC 50.502(g), a permit that is classified under 18 AAC 50.508(3) is not also classified under 18 AAC 50.502.

4. EMISSION UNIT INVENTORY

For ease of reference the department is including Table 1 which shows the emission units at the Dillingham Power Plant. The official emission unit inventory is provided in the permit.

Table 1 – Emission Unit Inventory

Emission Unit No.	Equipment Type	Make	Model	Capacity
3	Diesel Electric Generator	White Superior	405X8	350 kW-e
5	Diesel Electric Generator	White Superior	40V5X-12	750 kW-e
6	Diesel Electric Generator	White Superior	40VX-16	1,100 kW-e
10	Diesel Engine	Caterpillar	3516DI	1,135 kW-e
11	Diesel Engine	Caterpillar	3512B	1,050 kW-e
12	Diesel Engine	Caterpillar	3512B	1,050 kW-e
13	Diesel Engine	Caterpillar	3512B	1,050 kW-e
14	Diesel Engine	Caterpillar	3512C	1,050 kW-e
15	Diesel Engine	Caterpillar	3512C	1,050 kW-e

[2] Alaska regulations in 18 AAC 50.508(3) adopt the provisions of 40 CFR 60.52.21(aa) for *Actuals PALs*. A PAL permit is an approach that provides a Permittee the ability to manage source-wide emissions without triggering major New Source Review. Each PAL is pollutant specific. A permitting authority establishes a PAL by determining the baseline actual emission for all emission units at the source and adding the PSD significance level for that pollutant.

As required in 40 CFR 52.21(aa)(3), a PAL permit application is required designate each emission unit at the stationary source as small, significant, or major. The PAL monitoring requirements vary depending on the emission unit classification. The emission unit classifications from the application are shown in Table 2.

Table 2 – PAL Emission Unit Classification

Emission Unit No.	NO_x	SO_2	PM-10	CO
3	Significant[a]	Small[c]	Small	Small
5	Major[b]	Small	Small	Small
6	Major	Small	Small	Small
10	Major	Small	Small	Small
11	Major	Small	Small	Small
12	Major	Small	small	Small
13	Major	Small	Small	Small
14	Significant	Small	Small	Small
15	Significant	Small	Small	Small

Table Notes:
a – Significant has the meaning defined in 40 CFR 52.21(aa)(2)(xi)
b – Major has the meaning defined in 40 CFR 52.21(aa)(2)(iv)
c – Small has the meaning defined in 40 CFR 52.21(aa)(2)(iii)

5. PROJECT EMISSIONS SUMMARY

Table 3 shows the source wide emissions, for each pollutant covered by a PAL in this permitting decision. This shows the stationary source's baseline actual emissions[3], the allowed increase under the PAL, and the proposed PAL level versus the current PTE.

[3] As defined in 40 CFR 52.21(b)(48(i) for any existing electric utility steam generating unit, *baseline actual emissions* means the average rate, in tons per year, at which the unit actually emission the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. . ..”

Table 3 – Stationary Source Wide Emissions

	NO_X[f]	CO[f]	SO_2[g]	PM-10[f]
Currentc PTE[d]	326.0	97.3	63.3	7.1
Baseline Actual Emissions[e]	323.7[a]	60.9[a]	27.9[b]	5.5[a]
PAL Allowable Increase	<40	<100	<40	<15
Proposed PAL Level	363.6	160.8	67.8	20.4
Propose Increase	39.9	99.9	39.9	14.9
Proposed PAL Level vs. Current PTE	37.6	63.5	4.5	13.3
Acceptable for PAL?	Yes	Yes	Yes	Yes

Table Notes:
a - Emission calculated using actual power generated and averaged over two-year period ending February 13, 2006.
b - Based on SO_2 emissions reported in Facility Operating Report and averaged over two-year period ending September 15, 2005.
c – In this table, "current" means before issuance of Minor Permit No. AQ0214MSS01.
d – Current PTE does not include Emissions Units 14 and 15
e – Baseline Actual Emissions includes Emissions Units 5 and 6, however it does not include 14 and 15.
f – The NO_X, CO and PM-10 baseline dates are calculated using actual power generated and averaged over 2-year period ending February 13, 2006.
g – The SO_2 is based on SO2 emissions reported in Facility Operating Reports and averaged over 2-year period ending September 15, 2005.

6. DEPARTMENT FINDINGS

Based on a review of the application, the Department finds that:

1. The current Title I permits for the source will be rescinded and replaced with the requirements of four PALs in Minor Permit No. AQ0214MSS01.

2. The modifications to the current Title I permit terms and conditions are classified under 18 AAC 50.508(6).
3. The establishing of separate PALs for NO_X, CO, SO_2 and PM-10 is classified under 18 AAC 50.508(3).
4. The application satisfies the applicable requirements set out in 18 AAC 50.540 and the subsequent requirements for a PAL under 40 CFR 52.21(aa)(3) "Permit application requirements".

7. EMISSION UNIT INVENTORY

Under the provisions of a PAL permit, the Permittee is not subject to a restrictive emission unit inventory, and may add and remove emission units, while ensuring continuous compliance with state emission standards, ambient standards, increment and notifying the department of the addition of the emission unit. The stationary source wide emissions for each PAL pollutant must always stay below the PAL 12-month rolling average limit, no matter how many emission units are added or removed from the stationary source. The department has language contained in Condition 1, of the permit, stating that the emission unit inventory table is included with the permit for descriptive purposes only describing the initial inventory along with any foreseen near term changes to the inventory.

8. EMISSION UNITS 4 AND 5 REMOVAL

In the permit application, the Permittee requested engine replacement terms and conditions to be instituted to alleviate restrictive ambient conditions contained in Construction Permit 0025-AC003. The Department reviewed this request under 18 AAC 50.508(6) and 18 AAC 50.508(3). It is the Departments determination that these replacement terms and conditions are unnecessary, as the Permittee has shown compliance with all applicable requirements under the allowable PAL emissions levels for what the Department determined to be a conservative scenario. Since the new emissions units will not be installed until after the PAL effective date, and the Permittee is not looking at adding theses units, but to replace units that established the PAL levels, no new requirements are necessary as the PAL allows the Permittee to remove and replace emission units, as long as the Permittee continues to comply with all the requirements of the PAL.

9. PERMIT REQUIREMENTS

State regulations in 18 AAC 50.544 describe the elements that the Department must include in minor permits. This section of the TAR provides the technical and regulatory basis for the permit requirements in Minor Permit No. AQ214MSS01, which is classified under 18 AAC 50.508(3) and 18 AAC 50.508(6).

9.1. General Requirements for All Minor Permits

As described in 18 AAC 50.544(a), each minor permit issued under 18 AAC 50.542 must identify the stationary source, the project, the Permittee, contact information and fee information.

The permit cover page identifies the stationary source, the project, the Permittee, and the Permittee's contact information.

The Permit contains the fee requirements as defined under 18 AAC 50.400 – 18 AAC 50.499. The assessable emissions are 613 tons per year as shown in Table 4.

Table 4 – Assessable Emissions

	NO_x	CO	SO_2	PM-10	TOTAL
PAL Emissions	363.6	160.8	67.8	20.4	613

9.2. Requirements for a Permit that Revises or Rescinds a Previous Title I Permit

As described in 18 AAC 50.544(i) as minor permit classified under 18 AAC 50.508(6) must contain terms and conditions as necessary to ensure the Permittee will construct and operate the stationary source in accordance with 18 AAC 50.

9.2.1. State Emission Standards

The Department is including state emission standard for new Unit 14 and 15 in the permit. State emission standard requirements for existing equipment are covered in the operating permit. The Department will add periodic mr&r for the Units 14 and 15 when it incorporates this permit into the Title V permit.

9.2.1.1. Visible Emissions

Units 14 and 15 are new units authorized by this minor permit. The units are diesel engines are fuel-burning equipment and are subject to 18 AAC 50.055(a) for visible emissions.

The Permittee did not include a demonstration of compliance with the visible emissions state standard with the application, for Emission Units 14 and 15. Because diesel fuel-burning engines have the potential to exceed visible emissions standards, the Department is including conditions in the permit for the Permittee to perform a compliance demonstration on Emission Units 14 and 15, using 40 CFR 60, Appendix A, Reference Method 9 observation.

9.2.1.2. Particulate Matter

The diesel engines are fuel-burning equipment and are subject to 18 AAC 50.055(b) for PM emissions. The Permittee as part of their application submitted a particulate matter demonstration for Emission Units 14 and 15. The Department is not including an initial compliance demonstration condition for these units using 40 CFR 60, Appendix A.

9.2.1.3. Sulfur Dioxide

The diesel engines are fuel-burning equipment and are subject to 18 AAC 50.055(c) for SO_2 emissions.

The Department has previously calculated that emission units burning distillate fuel with less than 0.75 percent sulfur by weight will comply with the state SO_2 emission standard of 500 ppm. Since the American Society of Testing and Materials (ASTM) limits fuel sulfur to less than 0.5 percent (by weight) for diesel fuel. The Permittee will be using liquid diesel fuel oil with less than or equal to 0.50 percent sulfur by weight, the Department is not including an initial compliance demonstration in the minor permit for the emission units.

9.2.2. Ambient Air Quality Standards and Increments

The Permittee submitted an ambient air quality modeling assessment to demonstrate that they can comply with the Alaska Ambient Air Quality Standards (AAAQS) listed in 18 AAC 50.010. The Department reviewed the modeling assessment and has determined that the stationary source does not cause or contribute to an ambient standard or increment violation. The Department's review of the assessment is included in Appendix A of this TAR. The ambient air quality protection requirements are contained in Section 3 of minor permit AQ214MSS01.

9.3. BACT Requirements

Under 40 CFR 52.21(aa)(1)(iii), the Permittee shall continue to comply with all applicable State and Federal requirements, emissions limitations, and work practice requirements that were established prior to the effective date of the PAL. Under this requirement, the Permittee is still subject to the BACT requirements previously established in Construction Permit 0025-AC003 for Emissions Units 11, 12, and 13. Since the Permittee completed the source testing requirement established in the original BACT decision, the department has not carried that condition forward.

A copy of the TAR has been included in Appendix B to this TAR for ease of reference

9.4. PAL Provisions

The Permit contains all necessary terms and conditions to meet the requirements for a PAL permit under 40 CFR 52.21(aa)(7) and to protect ambient air.

9.4.1. Initial Emission Factor Validation and Ongoing Re-Validation Source Testing

9.4.1.1. Significant Emission Units

Emission Units 3, 14, and 15 are defined as significant units under 40 CFR 52.21(aa)(2)(xi), initial site specific source testing, and ongoing validation source testing may be implemented by the Department, under authority of 40 CFR 52.21(aa)(12)(vi)(c) and 40 CFR 52.21(aa)(12)(ix) respectively.

9.4.1.2. Major Emission Units

Emission Units 5 through 13, are defined as major emissions units under 40 CFR 52.21(aa)(iv). The language in the CFR currently does not contain the specific requirements for major emission units for the initial site specific source testing under 40 CFR 52.21(aa)(12)(vi)(c) as it does for the significant emission units, even though the major emission units are greater in emission production than the significant units. The department questioned the EPA if it had intended that major emission units should be included under the same requirements for initial site specific source testing and ongoing validation source testing as the significant emission units. The EPA told the department that the EPA's intention in the PAL permits was to source test all major and significant emission units at the permit initiation, and all units be tested for re-validation. The CFR has a provision under 40 CFR 52.21(aa)(7)(x), that allows the Department to include all requirements deemed necessary to enforce the PAL. The Department is including site specific source testing for all emission units under that authority.[4] The ongoing validation source testing is authorized under 40 CFR 52.21(aa)(12)(ix) for the major emission units.

The source testing that the Permittee provided for Emission Units 11, 12, and 13 is from 2002. The source test data provided in the application will be older than five years prior to the issuance of the minor permit and the effective date of the PALs. The Permittee is required to verify, through site specific source testing, within six months of issuance of this permit, the emission factors for NO_X, PM-10, and CO for Emission Units 11, 12, and 13. The PAL permitting requirements include verification of emission factors through source testing within five years of the last source test for all emission units. This requirement will include an initial demonstration for Emission Units 11, 12, and 13.

9.4.1.3. Small Emission Units

The CFR has a provision under 40 CFR 52.21(aa)(7)(x), allows the Department to include all requirements deemed necessary to enforce the PAL. The Department is including site specific source testing for small emission units under that authority for emission units designated under small per 40 CFR 52.21(aa)(2)(iii) to protect the limitation established for CO and PM-10. All of the initial inventory emission units are designated as small for CO and PM-10. These emissions units are still a sizeable portion of the limitation on a percentage basis, in a similar ratio to the major and

[4] The Department has conferred with EPA's PAL expert and subsequently discussed with Region 10, and this is a correct interpretation of the intent of the CFR's.

significant emission units are for the larger NOx PAL. Thus, the emission factor associated with these emission units and their error can still have an impact on maintaining compliance with the PAL, especially with the addition of any future emission units as allowed under the PAL provisions.

The ongoing validation source testing is authorized under 40 CFR 52.21(aa)(12)(ix) for the small emission units.

9.4.2. Emission Unit Groups

The department is allowing the Permittee to test a representative emission unit for groupings of emission units that are all the same make, model, rating, the same configuration, and are driving the same size generator.

For the validation testing under 40 CFR 52.21(aa)(12)(vi)(c), the department is doing this under authority of 40 CFR 52.21(aa)(12)(vi)(c), where the department has interpreted "unless the administrator determines that source testing is not required" to allow for the source testing a single representative emission unit for a grouping of emission units that are all the same make, model, rating, the same configuration, and are driving the same size generator.

For the re-validation, the department is doing this under authority of 40 CFR 52.21(aa)(12)(ix), where other scientifically valid means to verify the data used to establish the PAL pollutant is authorized. The department has interpreted this to allow the testing of a representative emission unit for a grouping if all the emission units are the same make, model, rating, the same configuration, and are driving the same size generator, thus should have similar emissions characteristics.

The department is allowing this under this permitting action as it currently does not have evidence to support that the emission units that are all the same make, model, rating, the same configuration, and are driving the same size generator will have statistically significant differences in emission factors.

9.4.2.1. Initial Emission Unit Groupings

The department is establishing emission unit groupings for emission units that are of the same make model, size, generator size, and configuration. Emission Units 11 through 13 are established as a grouping at the onset of the permit, as well as Emission Units 14 and 15 as a separate grouping.

9.4.2.2. How to Establish a Grouping after the Start of the PAL

The department has included provisions under each PAL, which the Permittee may request relief from source testing all the remaining emission units, and only testing a representative emission unit under the emission unit validation and re-validation source testing requirements. The emission units in the grouping have the same horsepower rating and model number, have the same generator size being driven, and have the same configuration. The department will review the request and if the department does not object, the emission unit grouping will be established 30 days after the department's receipt of the request.

9.4.3. Emission Factor Adjustment from Source Testing

The source testing performed must determine the worst case emission factors for the emission unit being tested, for each PAL emissions that uses emission factors for showing compliance with the PAL. This is because under 40 CFR 52.21(aa)(vi)(b), it states that "the emission unit shall operate within the designated range of use for the emission factor." If the emission factor is not worst case then the Permittee will not be able to operate the emission unit at all the other operational ranges. Since worst case will encompass all the other operational ranges, for the emission unit, the department will require the Permittee to perform the source testing to determine the worst case emission factor, to allow the operational flexibility of not being restricted to a single operational load and rpm level, for each and every emission unit.

The Permittee must use best engineering estimates to determine the worst case condition for performing the source test. The testing must be done within the operational range that the Permittee operates their engines. If the Permittee only operates between 50 percent and 100 Percent load and the worst case emission factor is at 5 percent load, since the Permittee does not operate at that load, only transitions through that load for startup and shutdown, that load would not be considered worst case for this purpose. This is unless the Permittee wishes to operate at the load in the future, then that load would need to be evaluated. The department is allowing that since the Permittee only operates within a certain operational range that the worst case load in that operating range would be where the Permittee should estimate the worst case condition by engineering means and perform the worst case emission factor test at that load.

The Permittee shall submit the worst case emission factor from the source test for department review. The department will review the submittal and only issue a response if the department objects to the emission factor. It is envisioned that any objection would be due to an error in the process in which it was derived from, including an error in the source testing performed, in the calculations, it is not worst case emission factor, or from other paths of error in the process. When the department objects, it should include a path to remedy the error and how to resubmit a revised emission factor for department review.

The emission factor tables initially included with each PAL are intended to be solely the initial emission factors used until site specific, worst case, emission factors can be derived from source testing. The department intends that all the emission factors contained in the tables will be replaced at the end of the initial emission factor validation source testing, and updated at least every five years from the revalidation source testing. If the Permittee does not successfully complete source testing and derive a new emission factor, that source testing shall not count towards satisfying the requirements to successfully complete source testing within six months of the PAL effective date or the requirement to revalidate the emission factors at least every five years.

9.4.4. New Emission Unit or Replacement Generator Source Testing Requirements

The Department authorized the use of emission factors on a kilowatt hour basis for the Permittee to show compliance with the NO_X, CO and PM-10 PALs. In order to ensure that the Permittee is complying with the PAL when adding a new emission unit or replacing a generator, the Department is requiring unit specific source testing to generate emission factors for these changes. The Department has authority under 40 CFR 52.21(aa)(7)(x) add this requirement. The requirement is necessary to ensure compliance with the NO_X, CO and PM-10 PALs, as the emission factors being used to show compliance with the PAL are derived specifically for the combination of fuel burning equipment and a specific generator, if either of these changes the emission factor could change. The department has is not requiring source testing for emission units that replace a generator with another of the same make, model and generating capacity, as the engine should operate at the same operating line for an identical generator, therefore have very similar emission characteristics.

9.4.5. Emission Factor Adjustment Due to Emission Factor Error

The emission factors for Emission Units 3, 4, and 5 are from the EPA's AP-42 tables. These emission factors have an inherent error associated with them as they are developed using a variety of sources that are not site specific and sometimes through unproven and generally unacceptable methods.[5] Under authority of 40 CFR 52.21(aa)(12)(vi)(a), the Department has the authority to adjust the emission factors to account for the uncertainty associated with their development. Although there is not a quantifiable methodology to account for and determine the specific error, the Department can perform a qualitative review of the error.

In this permitting action the Department is using its discretion not to implement an error adjustment factor for the emission factors. This is based on the use of site specific source testing to verify and adjust the emission factors. The emission factors obtained from the initial site specific source testing will be used retroactively for showing compliance from the start of the PAL, and will ensure compliance with the PAL.

9.4.6. Effective Date of Each PAL

The PAL effective date for each of the four PALs contained in this permit will be *one* day after the issuance of the minor permit. This is to accommodate for the requested changes under 18 AAC 50.508(6) to be established before the PAL takes effect. The requirements under a PAL state that all ambient conditions that are in place before the PAL takes effect, are effective for the period of the PAL. Some of the changes requested by the Permittee modify or rescind some of the ambient air quality conditions contained in the current construction permit. The Department has found that a permitting action for a PAL can not change the ambient requirements that are in place at the time of the PAL issuance. The Permittee successfully demonstrated

[5] Language paraphrased from the EPA's introduction to the Fifth Edition of the *Compilation of Air Pollutant Emission Factors* (AP-42).

compliance for both ambient standards and increments for the requested changes. The Department, will make the effective date of the PAL as one day after the issuance of the combined 18 AAC 50.508(3) and 18 AAC 50.508(6) permit. This will allow the changes under the 18 AAC 50.508(6) to be established before the effective date of the PAL, thus eliminating any ambiguity in the changing of ambient conditions under the effective date of the PAL.

9.4.7. Effective Period for Each PAL

Under the requirements of 40 CFR 52.21(aa)(8)(i), the permit contains a specified effective period of 10 calendar years for each regulated NSR pollutant specific PAL from the effective date of the PAL.

9.4.8. Establishing the PAL Level

To establish a PAL, the Permittee must base the PAL level on a review of a 24-month period of actual emissions for each requested regulated NSR pollutant at the stationary source. The period that is used may be different for each pollutant. Under 40 CFR 52.21(aa)(6) the Permittee must calculate the PAL level for each pollutant by adding the PAL allowable increase, which is equal to just below the PSD major modification level, to the two year average actual emissions. A demonstration, for Minor Permit AQ0214MSS01, is found in Table 3 and meets all the criteria outlined in 40 CFR 52.21(aa)(6).

9.4.9. Additional Discussion on PAL Monitoring with Emission Factors

The Permittee must monitor and record the stationary sources' compliance with the PAL on a monthly basis and provide semi-annual reporting to the Department. This should not be a change for an existing stationary source, as the Department requires at least semi-annual reporting in both Minor Permits and Operating Permits. The Permittee must maintain records necessary to determine compliance with the PAL, and these records must be maintained for five years. The Permittee must retain a copy of the PAL permit and any applications for revisions for five years beyond the effective period of the PAL. The monitoring requirements are as set out by 40 CFR 52.21(aa)(12), the recordkeeping requirements are set out in 40 CFR 52.21(aa)(13), and the reporting requirements are as described under 40 CFR 52.21(aa)(14).

9.4.10. Monitoring Sulfur Dioxide with Mass Balance

The Department under authority of 40 CFR 52.21(aa)(12)(i)(c), is using its discretion to grant the request by the Permittee to allow the demonstration of compliance with the Sulfur Dioxide PAL by the use of a sulfur mass balance. The federal rules do not contain a direct allowance for the use of mass balance for showing compliance with sulfur dioxide, under the four acceptable methods contained under 40 CFR 52.21(aa)(12)(ii), however it does have an allowance for the Department to authorize alternative methods at its discretion.

9.5. Fuel Meter Accuracy Requirement

The department has established a minimum fuel meter accuracy of plus or minus five percent. The department's intention with the required accuracy is that it accounts for both the initial accuracy and the drift associated with the meter between calibration intervals. If the meter is defined solely as the initial accuracy, then there are two relevant undesirable possibilities, where either the meter may drift unchecked or the Permittee could possibly be significantly burdened by constant (short time interval) calibration to maintain the meter at the initial installation accuracy. The department intends that the five percent accuracy allowance provides a reasonable time between calibrations while restricting the error associated with the meter.

9.6. Fuel Oil Sulfur Content Monitoring

The department has included requirements in the SO_2 PAL for fuel oil sulfur content monitoring. The fuel oil sulfur content shall be initially measured and that sulfur content starts a cycle of calculating average sulfur contents for the tank. The tanks sulfur content and the volume of remaining fuel at the time of deliveries will be used in conjunction with the delivered fuel amount in gallons and the delivered fuel oils sulfur content on a weight basis (weight) to calculate a new tank average for fuel sulfur. Every time a delivery occurs, the volume of the remaining fuel and its sulfur content (weight) will be used in conjunction with the newly delivered fuel oil and its sulfur content (weight) to get the new sulfur content (weight). The new sulfur content shall be the average based on the ratio of the sulfur content (weight) of the volume remaining and the delivered fuel.

The remaining fuel oil volume should be determined by using the total quantity of fuel remaining in each tank shall be measured using a strapping tape. The strapping tape shall be inserted into the tank and the level of the fuel oil in the tank be measured. This length shall then be converted into the total gallons of fuel available based on information in the fuel tank strapping chart. For each fuel tank, the Permittee shall use the correct strapping chart for that tank.

If there is no data for the tank or the delivered fuel for sulfur content the fuel sulfur content (weight) of the tank may either be measured via one of the acceptable methods, or a default value of 0.5 percent sulfur (weight) for the full tank and 0.5 percent sulfur (weight) must be used as the sulfur content (weight) value when calculating the future tank average. If the Permittee measures the fuel sulfur content (weight) and no new deliveries have been made in-between the last delivery and the time when the measurement occurs, that measured sulfur content shall be used for showing compliance with the SO_2 PAL for the period between the measurement and the last delivery and forward from the measurement until the next delivery. If a delivery had occurred in-between, then for the period from the last delivery to the delivery prior to that, the Permittee shall use 0.5 percent sulfur (weight) for that full period. The measured fuel sulfur content (weight) shall be used from the last delivery until the next delivery, and the Permittee calculates or measures a new average fuel sulfur content (weight) for the tank.

9.7. Recordkeeping, Reporting, and Certification Requirements

All air quality control permits must contain procedures for recordkeeping, reporting, and certification.

Information request and certification requirements in Section 6 of the minor permit are specifically required under 18 AAC 50.200 and 18 AAC 50.205, respectively.

9.8. Terms to Make Permit Enforceable

The minor permit contains additional requirements as necessary to ensure that the Permittee will construct and operate the stationary source in accordance with 18 AAC 50, as described in 18 AAC 50.544(i). These requirements are listed in the minor permit under "Terms to Make Permit Enforceable."

10. PERMIT ADMINISTRATION

Permittee may operate the Dillingham Power Plant under the conditions of Minor Permit AQ214MSS01 upon issuance.

Appendix A Modeling Memorandum

MEMORANDUM

State of Alaska
Department of Environmental Conservation
Division of Air Quality

TO: File

DATE: September 25, 2007

FILE NO.: AQ0214MSS01 – Modeling

THRU: Alan Schuler, P.E.
Environmental Engineer
Air Permits Program

PHONE: 269-7577
FAX: 269-7508

FROM: Patrick Dunn
Environmental Engineer Assistant
Air Permits Program

SUBJECT: Review of Nushagak's Dillingham Powerplant PAL Ambient Assessment

This memorandum summarizes the Department's findings regarding the Dillingham Powerplant ambient analysis submitted by Nushagak Cooperative Inc. (Nushagak). Nushagak submitted the analysis in support of their May 11, 2007 application for plantwide applicability limitations (PALs) for oxides of nitrogen (NO_X), sulfur dioxide (SO_2,) particulate matter less than 10 microns in diameter (PM-10) and carbon monoxide (CO). Per 40 CFR 52.21(aa), adopted by reference in 18 AAC 50.040, a separate PAL is required for each pollutant. As described in this memorandum, Nushagak's assessment adequately shows that operating their emission units within the requested constraints will not cause or contribute to a violation of the Alaska Ambient Air Quality Standards (AAAQS) and increments provided in 18 AAC 50.010 and 18 AAC 50.020.

BACKGROUND

Nushagak is currently permitted under Air Quality Control Construction Permit 0025-AC003, Revision 3 as a Prevention of Significant Deterioration (PSD) major source for NO_X. The Department imposed several conditions in Air Quality Control Construction Permit 0025-AC003 to protect the AAAQS including restrictions on stack heights and sampling port requirements. The Department also imposed several limits on the power generation of individual emission units or groups of emission units to protect the nitrogen dioxide (NO_2) and SO_2 increments.

Nushagak is requesting in their minor permit application to revise Construction Permit 0025-AC003, revision 3. Nushagak is requesting to replace two White Superior engines with two Caterpillar 3512C engines and to replace existing power generation limits with the PALs. Rather than revising the construction permit, the Department is rescinding the construction permit and establishing the PALs through a minor permit. The Department is also revising conditions in Operating Permit No. AQ0214TVP01 through the operating permit renewal process.

Nushagak's application triggers minor permit review under 18 AAC 50.508(6) and 18 AAC 50.508(3). Per 18 AAC 50.540(k)(3), applicants subject to 18 AAC 50.508(6) must include in their application the effects of revising permit terms and conditions. Per 18 AAC 50.540(h), applicants subject to 18 AAC 50.508(3) must provide an ambient AAAQS analysis for the pollutants under the PAL. Therefore, Nushagak provided an ambient NO_X, SO_2, PM-10 and CO AAAQS analysis under 18 AAC 50.540(h) and a NO_X and SO_2 ambient increment analysis under 18 AAC 50.540(k)(3)

Nushagak submitted a modeling protocol on November 22, 2006. The Department received additional information and revisions through March 28, 2007.The Department approved the protocol with minor comment on April 17, 2007.

APPROACH

Nushagak used computer analysis (modeling) to predict the ambient air quality impacts. Steigers Corporation (Steigers) conducted the modeling analysis on behalf of Nushagak.

Nushagak modeled three scenarios that may occur under the PALs. Phase 0 consisted of the existing emission units, Phase 1 consisted of the replacement of one White Superior engine with one Caterpillar engine, and Phase 2 consisted of the replacement of both White Superior engines with Caterpillar engines.

Ambient air quality impacts less than the significant impact levels (SILs) listed in Table 5 of 18 AAC 50.215(d) for a given averaging period are considered negligible. If ambient air quality impacts exceed the SILs then a cumulative ambient air quality impact analysis including off-site sources must be performed to show compliance with the standards and increments. Nushagak took a slightly different approach by including off-site sources in their SIL analysis. The total CO impacts are less than the SILs. The total NO_X, SO_2 and PM-10 impacts are greater than the SILs and must be compared to the air quality and increment standards. The numerical values are listed in the results section of this memorandum.

For the increment analysis, Nushagak modeled negative emission rates for units that were in operation prior to the increment baseline dates but have since been retired or that will be shutdown as part of the minor permit. Nushagak also modeled negative emission rates and original stack heights for units which have had stack changes since the baseline dates. For these units which have had stack changes Nushagak also used positive emission rates with current stack heights.

The Department requested in the April 17, 2007 protocol approval letter that Nushagak use the baseline stack parameters and emission rates used in their January, 1999 construction permit application. Nushagak used the requested 1979 baseline data for the SO_2 increment analysis but used 1987 baseline data for the NO_X increment analysis. Nushagak had previously used an average of 1983 through 1984 data for the NO_X analysis in the 1999 construction permit application. Although the NO_X data was not what the Department originally approved it is appropriate for this analysis because it reflects conditions immediately prior to the February 8, 1988 baseline date.

Model Selection
There are a number of air dispersion models available to applicants and regulators. The U.S. Environmental Protection Agency (EPA) lists these models in their *Guideline on Air Quality Models* (Guideline). Nushagak used EPA's *AERMOD Modeling System* (AERMOD) for the ambient analysis. AERMOD is an appropriate model for this analysis.

The AERMOD Modeling System consists of three components: AERMAP (which is used to process terrain data and develop elevations for the receptor grid), AERMET (which is used to process the meteorological data), and AERMOD (which is used to estimate the ambient concentrations). Nushagak used the current version for AERMET and AERMAP (06341) and the current version for AERMOD (07026).

EPA listed the AERMOD Modeling System as a Guideline method on November 9, 2005. However, the Department has not yet updated our adoption by reference of the Guideline. Therefore, AERMOD is still a non-Guideline model under state regulation.

Applicants using non-Guideline models must obtain case-by-case approval from the Commissioner per 18 AAC 50.215(c)(3). The Commissioner delegated the responsibility for approving non-Guideline methods to Tom Chapple (Director, Air Division) on February 23, 2006. The Director approved the use of AERMOD for the Nushagak application on December 27, 2006.

Use of a non-Guideline model is also subject to public comment. Therefore, the Department is seeking public comment regarding the use of AERMOD in the public notice regarding the preliminary permit decision.

Meteorological Data
AERMOD requires hourly meteorological data to estimate plume dispersion. According to the Guideline, five years of adequately representative data should be used (when available) to account for year-to-year variation.

Nushagak used five years (July 1, 2000 through June 30, 2001 and July 1, 2002 through June 30, 2006) of surface data collected at the Dillingham airport. The Dillingham airport and the powerplant are located approximately 1.3 miles apart and there are no significant topographic features between them. Therefore the use of the Dillingham airport data is appropriate. Nushagak did not use consecutive data because of an inadequate data capture rate for the period July1, 2001 through June 30, 2002. Nushagak also used concurrent upper air data from the nearest available source, the National Weather Service (NWS) station in King Salmon.

EPA allows applicants to compare the high second-high (h2h) modeled concentration to the short-term air quality standards and increments if at least one year of temporally representative site-specific, or five years of representative off-site data, are used. Nushagak used the h2h modeled concentrations for comparison to the SO_2 short term AAAQS and PSD increments because five years of representative off-site data was used. EPA allows the 24-hour PM-10 AAAQS concentration to be modeled as the highest sixth-high (h6h) impact over a five-year meteorological period Nushagak used the h6h modeled concentrations for comparison to the PM-10 24-hour AAAQS because a five year meteorological period data was used.

AERMET requires site-specific values (representative of the meteorological site) for the following three surface characteristics: noon-time albedo, bowen ratio, and surface roughness length. Nushagak segregated the surrounding area into three sectors to define site-specific surface characteristics. Nushagak assigned the values by month in order to adjust the surface characteristics according to season. Nushagak also used a weighted average for surface characteristics for each month based on land use type in each sector. The values selected by Nushagak are shown in Table 13 and page 26 of their May 11, 2007 application. Nushagak used the surface characteristics accepted by the Department in the April 17, 2007 protocol approval.

Emission Unit Inventory
Nushagak modeled their existing emission units listed in Table 1 of their application for Phase 0. For Phase 1 Nushagak replaced either emission unit 5 or 6 with either emission unit 14 or 15 and for Phase 2 Nushagak replaced both units 5 and 6 with emission units 14 and 15. Nushagak also modeled three removed emission units for baseline credits in the PSD increment analysis.

The Department investigated the effects of operating emission units 5 and 6 concurrently with emission units 14 and 15. The Department found that Nushagak can meet short term AAAQS and increments under this scenario. Therefore the Department will not impose an ambient condition on the number of emission units which can operate concurrently.

The approximate location of the modeled units is shown in Figure 5 of the application.

Load Analysis
The maximum ambient concentrations do not always occur during the full-load conditions that typically produce the largest emissions. The relatively poor dispersion that occurs with cooler exhaust temperatures and slower part-load exit velocities may produce the maximum ambient impacts. Therefore, EPA recommends that part-load conditions be analyzed as well as full-load conditions.

Nushagak performed a load screening analysis for the Caterpillar 3512C engines. Nushagak previously performed an acceptable load screening analysis of the other emission units as part of their application for Construction Permit 0025-AC003, but included these units in the current load screening analysis for completeness. Nushagak performed a load screening analysis at 75 and 100 percent loads for all emission units and additionally performed a load analysis at 83 percent load (the annual average) for NO_2 impacts.

Nushagak modeled the emission units at the loads corresponding to the highest impacts with a few minor exceptions where differences were less than one percent. In these cases Nushagak modeled the emission units at 100 percent load. Nushagak's load screening analysis is appropriate

Emission Rates and Stack Parameters
The assumed emission rates and stack parameters have significant roles in an ambient demonstration. Therefore, the Department checks these parameters very carefully. The modeled emission rates and stack parameters are reasonable. However, the following parameters or assumptions warrant special comment.

Annual Operation
Nushagak initially assumed all of the emission units operate continuously (8,760 hours per year). The NO_2 analysis had to be refined further to meet the ambient AAAQS and PSD increments (See Ambient NO_2 Modeling below)

Stack Heights
Stack height can be a critical component of an ambient demonstration, especially when an emission unit is subject to downwash. Therefore, including minimum stack height requirements in the permit is sometimes warranted.

Nushagak assumed a 16.6-meter stack height for all of the emission units. The Department was told by Aseem Telang of Steigers in a phone conversation on September 14, 2007 that all emission unit stack heights are currently at least 55 feet (16.8 meters) above ground level. The Department requires through Condition 12 in Construction Permit 0025-AC003, revision 3 and Condition 9 in Operating Permit No. AQ0214TVP01, that emission unit 3 be no less than 45 feet above ground level and emission units 5 and 6 be no less than 50 feet above ground level. These permit conditions also require all other emission units be no less than 55 feet above ground level. Nushagak previously submitted to the Department as-built drawings showing emission units 3, 5, 6, 8, 9, 10 and 11 are at least 57 feet above ground. Emission units 12 and 13 have replaced emission units 8 and 9 and use the same stacks. Emission units 14 and 15 will replace emission units 5 and 6 and will use the same stacks. The Department will require that stack heights be maintained at no less than 16.6 meters as a permit condition to protect ambient air quality.

Horizontal/Capped Stacks
The presence of non-vertical stacks or stacks with rain caps requires special handling in an AERMOD analysis.

None of the emission units were modeled with horizontal or capped stacks. The construction permit does not have a condition requiring vertical uncapped stacks. The Department will require all emission units to have un-capped vertical stacks as a permit condition in the minor permit because this is an appropriate condition based on the modeling analysis assumptions.

Ambient NO_2 Modeling
Nushagak initially modeled all emission units operating continuously, The annual potential to emit (PTE) NO_X emissions with this scenario were over twice the NO_X PAL for all three scenarios. This very conservative approach resulted in modeled violations of the NO_2 AAAQS and increment. Nushagak then determined which emission units had the highest NO_2 impacts.

They assumed the emission unit with the highest impact operated continuously. They then assumed the next highest impacting unit operated as much as possible within what remained of the PAL emissions. Nushagak repeated this process until the total NO_X emissions from the highest impacting emission units equaled the NO_X PAL.

For Phase 0, there are three emission units which contribute the greatest impact for both AAAQS and increment. Nushagak modeled Phase 0 with these three emission units with their NO_X emissions totaling 100 percent of the NO_X PAL. For Phase 1 there were four emission units which contribute the greatest impact for both AAAQS and increment. Nushagak modeled Phase 1 with these four emission units with their NO_X emissions totaling 137 percent of the NO_X PAL. For Phase 2 there were also four emission units which contribute the greatest impact for both AAAQS and increment. Nushagak modeled Phase 2 with these four emission units with their NO_X emissions totaling 125 percent of the NO_X PAL. Nushagak's approach to show compliance with the AAAQS and PSD increments is conservative and therefore acceptable. The Department will include complying with the NO_X PAL as a permit condition because the maximum modeled ambient concentrations are nearly 80 percent of the AAAQS.

The modeling of ambient NO_2 concentrations can sometimes be refined through the use of ambient air data or assumptions. Nushagak used the national default ambient NO_2-to-NOx ratio of 0.75, as provided in EPA's *Guideline on Air Quality Models*, to refine the estimated ambient NO_2 concentrations. The 0.75 ratio is appropriate for this analysis.

Ambient SO_2 Modeling
SO_2 emissions are directly related to the amount of sulfur in the fuel. Nushagak modeled the fuel sulfur level of all emission units at 0.5 percent, by weight. The Department will include the modeled fuel sulfur limit as a permit condition. The modeled unrestricted PTE for SO_2 emissions for all three phases was over twice the SO_2 PAL. Nushagak used the unrestricted SO2 PTE in their analysis, therefore Nushagak's approach is therefore conservative and acceptable.

Ambient PM-10 Modeling
The unrestricted PM-10 PTE was less than the PM-10 PAL for all three scenarios. Nushagak therefore equally prorated the PM-10 emissions for each emission unit for each scenario so that the total modeled emissions equaled the PM-10 PAL. Nushagak's approach is therefore conservative and acceptable.

Ambient CO Modeling
The unrestricted CO PTE was greater than the CO PAL for all three scenarios. Nushagak used the unrestricted CO PTE in their analysis, Nushagak's approach is therefore conservative and acceptable.

Off-Site Impacts
The ambient analysis must address potential air quality impacts from off-site stationary sources. These impacts are typically assessed through modeling. Nushagak included the same off-site source as previously used and approved: Peter Pan Seafoods. The inclusion of Peter Pan Seafoods is appropriate.

Background Concentration
The background concentration represents impacts from sources not included in the modeling analysis. Typical examples include natural, area-wide, and long-range transport sources. The background concentration must be evaluated on a case-by-case basis for each ambient impact analysis. Once the background concentration is determined, it is added to the modeled concentration to estimate the total ambient concentration.

Nushagak used the same background concentrations as in the 2000 PSD permit decision[6] for the Dillingham Power Plant. The NO_2 value is the maximum concentration measured in Dutch Harbor during a monitoring program jointly conducted by the City of Unalaska and UniSea between May 1997 and April 1998. The SO_2 and PM-10 values were measured in Healy between 1990 and 1991. CO values were not needed because Nushagak showed compliance with the CO SILs. The numerical values are listed in the results section of this memorandum.

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Ambient Air Boundary
For purposes of air quality modeling, "ambient air" means outside air to which the public has access. Ambient air typically excludes that portion of the atmosphere within a stationary source's boundary. Fencing creates a legitimate ambient air boundary. Non-fenced areas within the Nushagak's property boundary are considered ambient air. Nushagak appropriately included the non-fenced areas of their property boundary as ambient air

Receptor Grid
Nushagak stated they used the following receptor grid density:

- 25-meter spacing within and along the Dillingham Power Plant boundary (DPPB),
- 50-meter spacing extending 700 meters from the DPPB,
- 100-meter spacing between distances of 700 and 1,200 meters from the DPPB,
- 250-meter spacing between distances of 1,200 and 3,000 meters from the DPPB, and
- 1 kilometer spacing between distances of 3 and 10 kilometers from the DPPB.

The Department noted some irregularities in the receptor grid boundary, but the Department found the receptor grid adequate for this analysis.

Nushagak further refined the receptor grid boundary for any pollutant where the maximum concentration was more than 50 percent of the AAAQS or increment. NO_X was the only pollutant that met this criterion. Therefore, Nushagak used the refined grid for the NO_X analysis. This was appropriate for the NO_X analysis

Downwash
Downwash refers to conditions where nearby structures influence the plume pattern. Downwash can occur when a stack height is less than a height derived by a procedure called "Good Engineering Practice," as defined in 18 AAC 50.990(42). The modeling of downwash-related impacts requires the inclusion of dimensions from nearby buildings.

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[6] The Department used a different NO_2 value in the 2000 PSD permit decision compared to the one Nushagak submitted with the 1999 construction permit application.

EPA has established specific algorithms for determining which buildings must be included in the analysis and for determining the profile dimensions that would influence the plume from a given stack. Nushagak used the current version (04724) of BPIPPRM to determine the building profiles needed by AERMOD.

RESULTS AND DISCUSSION

The maximum CO impacts for any of the three scenarios are shown in Table 1, along with the SIL. Since the 1-hour and 8-hour CO impacts are less than the applicable SIL, Nushagak has demonstrated that the project will not cause or contribute to a violation of the CO AAAQS.

Table 1: CO Project Impacts

Air Pollutant	Avg. Period	Project Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)
CO	1-hour	**200**	2,000
	8-hour	**157**	500

The maximum AAAQS impacts for any of the three scenarios are shown below in Table 2. The background concentrations, total impacts and AAAQS are also shown. As shown in Table 2 the total impacts are less than the respective AAAQS. Therefore, Nushagak has demonstrated compliance with the AAAQS.

Table 2 – Maximum AAAQS Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc ($\mu g/m^3$)	Bkgd Conc ($\mu g/m^3$)	TOTAL IMPACT: Max conc plus bkgd ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
NO_2	Annual	61.2	18.6	**79.8**	100
SO_2	3-hr	114	44	**158**	1,300
	24-hr	93	26	**119**	365
	Annual	22	5	**27**	80
PM-10	24-hr	13	31	**44**	150
	Annual	3.2	5.0	**8.2**	50

The maximum PSD impacts for any of the three scenarios are shown below in Table 3. The Class II increments are also shown. As shown in Table 3 the total impacts are less than the respective PSD increments. Therefore, Nushagak has demonstrated compliance with the PSD increments.

Table 3 - Maximum Increment Impacts

Air Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Class II Increment Standard ($\mu g/m^3$)
NO_2	Annual	**11.9**	25
SO_2	3-hr	**52**	512
	24-hr	**28**	91
	Annual	**5**	20

It is important to note that since ambient concentrations vary with distance from each emission unit, the maximum value represents the highest value that may occur within the area. The concentrations at other locations within the area should be less than the value reported above.

CONCLUSION

The Department reviewed Nushagak's modeling analysis for the Dillingham Power Plant PAL and concluded the following:

1. The NO_2, SO_2, PM-10 and CO emissions associated with the proposed PALs will not cause or contribute to a violation of the AAAQS listed in 18 AAC 50.010.
2. The NO_2 and SO_2 emissions associated with the proposed PALs will not cause or contribute to a violation of the increments listed in 18 AAC 50.020.
3. Nushagak's modeling analysis fully complies with the showing requirements of 18 AAC 50.540(h) and 18 AAC 50.540(k)(3).
4. Nushagak conducted their modeling analysis in a manner consistent with EPA's *Guideline on Air Quality Models.*

The Department has developed conditions in the Dillingham Power Plant PAL air quality control minor permit to ensure compliance with the ambient air quality standards and increments. These conditions are summarized below:

1. Limit the maximum sulfur content of diesel fuel to 0.5 percent, by weight,
2. Comply with the NO_X PAL,
3. Maintain a minimum stack height of 16.6 meters for all emission units, and
4. Maintain all emission units with vertical uncapped stacks. This condition does not preclude the use of flapper valve rain covers, or other similar designs, that do not hinder the vertical momentum of the exhaust plume.

Appendix B TAR from Permit 0025-AC003

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Juneau, Alaska

FINAL
TECHNICAL ANALYSIS REPORT

For Air Quality Control Construction Permit No. 0025-AC003

Nushagak Electric Cooperative
Prevention of Significant Deterioration
Dillingham Power Plant Project

May 8, 2000

Alaska Department of Environmental Conservation
Air Permits Program
410 Willoughby Avenue, Suite 105
Juneau, Alaska 99801-1795

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ABBREVIATIONS AND ACRONYMS

BACT	Best Available Control Technology
CEM	Continuous Emission Monitor
CFR	U.S. Code of Federal Regulations
CO	Carbon Monoxide
DEC	Alaska Department of Environmental Conservation
EGR	Exhaust Gas Re-circulation
EPA	U. S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FITR	Fuel Injection Timing Retard
hp	Horsepower
hr	Hour
H_2S	Hydrogen Sulfide
ISO Conditions	288K, 60 pct relative humidity and 101.3 kilopascals pressure
kW	Kilowatts
LAER	Lowest Available Emission Rate
MMBtu	Million British thermal units
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NO	Nitric Oxide
NO_X	Oxides of nitrogen
NO_2	Nitrogen Dioxide
OLM	Ozone Limiting Method
OSHA	Occupational Safety and Health Administration
PM	Particulate matter
PM-10	Particulate matter (10 micrometers or less in size)
ppmdv	Parts per million, dry volume basis
PSD	Prevention of Significant Deterioration
SCO	Selective Catalytic Oxidation
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
TSP	Total suspended particulate (30 micrometers or less)
VOC	Volatile organic compounds
$\mu g/m^3$	Microgram per cubic meter

1.0 INTRODUCTION

Nushagak Electric Cooperative, Inc. (NEC), owns and operates the Dillingham Power Plant located on 557 Kenny Wren Road in the town of Dillingham, Alaska (Section 16, Township 13 South, Range 55 West, Seward Meridian). The power plant, currently consisting of seven diesel-electric generators, generates and supplies electrical power to approximately 1,374 residential and commercial customers in the Dillingham valley. Dillingham is not linked to a regional electric power grid, so the city must rely upon the electric power generated from NEC. Federal Prevention of Significant Deterioration (PSD) and Alaska Air Quality Regulations designate the area adjacent to the Dillingham Power Plant as Class II. The nearest Class I area is the Tuxedni National Wildlife Refuge 350 kilometers east-northeast of Dillingham.

The electric generating facility was classified as a major source under the Prevention of Significant Deterioration regulations on August 7, 1980, for emitting greater than 250 tons per year (tpy) of nitrogen oxides (NO_X). Subsequent modifications should subject the facility to major source review if emission increases exceed the thresholds listed in 18 AAC 50.300(h)(3).

In 1984, NEC installed two 835 ekW Caterpillar diesel electric generators (Source No. 8 and 9). The potential to emit from these engines was greater than the 40-tpy applicability threshold level for NO_X. However, these sources were never evaluated for best available control technology (BACT) prior to installation due to an incorrect assessment by the Department and the applicant, during which that project was viewed as a minor modification. The Department recognized this oversight in February 1987; however, no permit was issued. On March 3, 1998, the Department and applicant agreed that existing Sources No. 8 and 9 would not require a BACT analysis as they were nearing the end of their useful life. However, future replacement sources would be required to install best available control technology through a PSD review.

The Department deemed NEC's construction permit application complete on January 26, 2000. The permit action will authorize the installation and operation of three diesel electric generators, Sources No. 11, 12, and 13, which replace existing Sources 4, 8, and 9, respectively. The replacement sources each require a BACT analysis for NO_X.

The Department finds that:

1. The NEC facility is an existing electric power plant classified as a PSD Major facility for NO_X emissions under the Department's Air Quality control Regulations as listed in 18 AAC 50.300(c)(1).
2. NEC submitted a construction permit application on January 19, 1999, and supplemented that application on April 27, 1999, April 29, 1999, July 29, 1999, and December 2, 1999.
3. The applicant has requested authorization to operate the existing diesel-electric generators (Sources No. 3, 4, 5, 6, 8, 9, and 10). Three of the generators (Sources No. 4, 8, and 9) will be retired and removed from site through this project modification.
4. The applicant has requested approval to install and operate three Caterpillar 3512B

Diesel Electric Generator Sources No. 11, 12, and 13 in replace of three existing diesel electric generators, Sources 4, 8, and 9, respectively.

5. The industrial processes and fuel burning equipment at the power plant are subject to the State Air Quality Control Regulations 18 AAC 50.055(a)(1) for visible emissions, 18 AAC 50.055(b)(1) for particulate matter, and 18 AAC 50.055(c) for sulfur compound emissions.
6. The replacement Sources No. 11, 12, and 13 are subject to major source review for NO_X for having emission increases greater than the PSD thresholds listed in 18 AAC 50.300(h)(3)(B)(ii).
7. To avoid a PSD review for SO_2, the Department is imposing a facility-wide limit of 63.3 tons of SO_2 per 12-month rolling period. This will limit SO_2 emission increases at the power plant to less than 40 tons per year.
8. To avoid a PSD review for CO, the applicant proposes to limit the annual power generation for Sources 11, 12, and 13. In addition, the Department is imposing a combined CO limit of 90.0 tons per 12-month rolling period for Sources No. 11, 12, and 13.
9. The applicant proposes the following controls as BACT for NO_X on Sources 11, 12, and 13: a lean-burn/low NO_X engine package operating under good combustion management. The engine package includes electronically controlled fuel injectors and a turbocharger/aftercooling system.
10. The applicant has one 24,000 gallon tank (installed in 1963), two 500,000 gallon tanks (installed in 1985), and one 850,000 gallon tank (installed in 1993). The two 500,000 gallon and one 850,000 gallon diesel storage tanks are subject to federal New Source Performance Standards (NSPS) 40 CFR 60, Subpart Kb, incorporated by reference in Alaska Air Quality Control regulation 18 AAC 50.040(a)(2)(M).
11. The applicant has shown that the facility, as permitted, will not cause or contribute to violations of the ambient NO_2 and SO_2 air quality standards and PSD increments.
12. The applicant proposes to increase the exhaust stack heights and limit the annual power generation of Sources No. 3, 5, 6, 8, 9, 10, 11, 12, and 13 as set out in the application to protect SO_2 and NO_2 ambient standards and increments. Those power generation limits for Sources No. 11, 12, and 13 are also to avoid PSD for CO emission increases from the project as listed in Finding 8.
13. The applicant proposes to burn distillate fuel oil with a maximum sulfur content of 0.50 percent by weight to protect SO_2 ambient standards and increments.
14. Emissions from the proposed sources will not impair air quality-related values such as visibility within Class I Areas.
15. The facility is located within the Bristol Bay Borough's Coastal Management District. Therefore, the project requires a project consistency determination under the Alaska Coastal Management Program (ACMP).
16. The application and supplements satisfy the applicable requirements set out in 18 AAC 50.310. Thus, the Department is proposing to grant NEC's request and issue Air Quality Control Construction Permit No. 0025-AC003 for the Dillingham Power Plant.

1.1 EMISSION SOURCES

The fuel burning equipment currently operating at the Dillingham Power Plant includes seven diesel-electric generators (Sources 3, 4, 5, 6, 8, 9, and 10). NEC requests approval to replace the existing Sources 4, 8, and 9 with three Caterpillar Model 3512B diesel-electric generators, Sources 11, 12, and 13. See Table 1.1-1 for source identification.

Table 1.1-1: Source Identification

No.	Source Description	Installation Date	Removal Date	Rated Capacity (ekW)
3	White Superior #405X8 Diesel Electric Generator	1962	--	350
4	Chicago Pneumatic #89A-CPS Diesel Electric Generator	1967	2000	500
5	White Superior #40V5X-12 Diesel Electric Generator	1974	--	750
6	White Superior #40VX-16 Diesel Electric Generator	1974	--	1,000
7	Alco 12-Cylinder Diesel Electric Generator	1980	1986	1,250
8, 9	Caterpillar #3516DI Diesel Electric Generators	1984	2000	835
10	Caterpillar #3516 Diesel Electric Generator	1988	--	1,135
11, 12, 13	Caterpillar #3512B Diesel Electric Generators (slow speed)	2000	--	1,050

Note: Source No. 7 was destroyed in 1986 by overspeeding and replaced by Source No. 10. The replacement occurred without a permit. The Department considered this modification a "like-kind" replacement.

Replacement of the three diesel-electric generators will occur in two phases: Configuration I is the installation of Source No. 11 and retirement of Source No. 4; and Configuration II is the installation of Sources No. 12 and 13 to replace Sources No. 8 and 9, respectively.

2.0 CLASSIFICATION

NEC is classified under: (1) 18 AAC 50.300(c)(1) – as a PSD major facility; (2) 18 AAC 50.300(h)(2) – as a modification that requires a demonstration to show compliance with the applicable air quality standards and increments; and (3) 18 AAC 50.300(h)(3) – as a modification that significantly increases the actual emissions of a regulated air contaminant.

2.1 PREVENTION OF SIGNIFICANT DETERIORATION PROGRAM

The Federal Clean Air Act established the PSD program to manage air quality by evaluating the emission controls and potential ambient air quality impacts from proposed new or modified major stationary sources. The U.S. Environmental Protection Agency (EPA) has approved Alaska's PSD pre-construction review program for new or modified stationary sources to the State of Alaska. The Alaska Air Quality Control Regulations, 18 AAC 50, contain the PSD pre-construction review program. Entities desiring to build or modify a facility subject to the PSD pre-construction review program must submit an application to the Department prior to constructing the facility or modification. The Department then reviews the emissions, proposed controls, and predicted ambient impacts, to determine whether the proposed facility/modification complies with the air quality standards and program requirements.

The facility is a "major" source as classified in 18 AAC 50.300(c)(1). The application describes a proposed modification classified as PSD-significant in 18 AAC 50.300(h)(3). Therefore, the Department requires this project to undergo pre-construction review under the PSD program and obtain an Air Quality Control Construction Permit. This review includes:

1. evaluating the potential to emit (PTE) from each modification;
2. determining the State and federal emission standards applicable to the project's emitting sources and the project's compliance with emission standards;
3. evaluating Best Available Control Technology (BACT) for new or modified emission units and establishing emission or operating limits, which represent BACT;
4. determining the attainment status of the air shed;
5. reviewing air pollution monitoring data regarding existing air quality and meteorological data in the vicinity of the project;
6. identifying the ambient air quality boundary for the facility;
7. assessing ambient air quality impacts of the project and associated activities relative to National and State Ambient Air Quality Standards (AAQS) and PSD increments; and
8. evaluating impacts of the project and associated activities on air quality-related values such as visibility, deposition effects on lands and waters, and effects on vegetation.

2.2 PSD APPLICATION REQUIREMENTS

PSD applicability for the Dillingham Power Plant was determined on a pollutant basis by comparing the net emission rate increase of the modification to the PSD thresholds listed in

18 AAC 50.300(h)(3)(B). The applicant calculated the net change using the facility-wide future potential to emit as limited in the application and the actual emissions determined from the most recent two years of representative operational data. For the Dillingham Power Plant, the most recent 2 years of representative data before the first of a series of modifications are from 1983 and 1984, based on the following reasoning.

In 1984, NEC installed two diesel-electric generators (Sources No. 8 and 9). The potential to emit from these engines was greater than the 40-tpy applicability threshold level for NO_X; thus, the change was a major modification. However, these sources were never evaluated for best available control technology (BACT). To correct this oversight, the applicant submitted a PSD construction permit application that analyzes the actual and proposed changes to the Dillingham Power Plant since 1984. As a result, the PSD evaluation is assessed using 1984 as the reference point for changes to the power plant. Therefore, the applicant excludes emission credits for the replacement of Sources 8 and 9.

The Department has conducted PSD reviews for each phase of the proposed modification: Configuration I is the installation of Source No. 11 and retirement of Source No. 4; and Configuration II is the installation of Sources No. 12 and 13 and retirement of Sources No. 8 and 9, respectively. The Department's reviews are described in this technical analysis report.

Table 2.2-1 shows this comparison for each pollutant and indicates whether a PSD review is required. See Appendix A for specific emissions calculations.

Table 2.2-1: PSD Applicability for the NEC Modification

Pollutant	Emission Increases (tpy)		PSD Thresholds (tpy)	PSD Review Required?
	Configuration I	Configuration II		
NO_X	239.2	138.9	40	yes
CO	27.9	51.9	100	no
SO_2	39.3	39.3	40	no
PM	1.8	1.0	25	no
PM_{10}	1.8	1.0	15	no
VOC	6.0	4.0	40	no
Pb	0	0	0.6	no
Fluorides	0	0	3	no
Sulfuric Acid Mist	0	0	7	no
Total Reduced Sulfur Compounds	0	0	10	no
H_2S	0	0	10	no

Note: The emission increases were calculated by comparing the future potential to emit as limited in the construction permit and application to the 1983-84 actual emissions.

4.1 To avoid a PSD review for SO_2, the applicant proposed to burn distillate fuel oil with a maximum sulfur content of 0.5 percent and limit the annual power generation of all fuel-burning sources. The Department imposed the 0.5 percent fuel sulfur limitation, but thought it more appropriate to limit facility-wide SO_2 emissions to 63.3 tons per 12-month rolling period which is representative of the annual generation limits requested. This will confine SO_2 emission increases to less than the 40-ton-per-year applicability threshold, but allow NEC the operational flexibility to use greater amounts of fuel at lower sulfur content levels.

4.2 To avoid a PSD review for CO, the Department is imposing annual power generation limitations for Sources No. 11, 12, and 13 as described in Table 2.2-2. In addition, the Department is imposing a combined CO limit of 90.0 tons per 12-month rolling period for Sources No. 11, 12, and 13 to confine CO emission increases to less than the 100-ton-per-year applicability threshold. The Department is requiring NEC to source test each of Sources No. 11, 12, or 13 to ensure that CO emissions are representative of the emission factors used to determine the 90.0 ton per 12-month total limit. The source tests shall be conducted at the time the engines are being source tested for the NO_X BACT requirements as set out in Section 4 of this report.

Table 2.2-2: Owner Requested Limits to Avoid PSD for CO

Source No.	Annual Power Generation Limit (ekW-hr/yr)	
	Configuration I	Configuration II
11	7,000,000	21,000,000
12, 13	N/A	

Note: Sources No. 3, 5, 6, 8, 9, and 10 also have annual power generation limits for each configuration to ensure compliance with the SO_2 and NO_2 standards and increments as described in Section 5 of this report.

Applicants for facilities or modifications subject to PSD pre-construction review must meet application requirements listed in 18 AAC 50.310(c) and (d). These requirements include: providing existing ambient air quality and meteorological data to describe the air quality in the vicinity of the project; conducting ambient air quality impact analysis to demonstrate that the facility/modification will not cause or contribute to a violation of applicable AAQS and PSD increments; assessing control technologies for BACT analysis; and demonstrating the project and associated activity impacts to air quality-related values including visibility, soils, noise, odor, and vegetation.

The Department found that the application and submittals contained the necessary information for the Department to prepare a preliminary construction permit decision.

Therefore, on January 26, 2000, the Department informed the applicant that the application is administratively complete under the State Air Quality Control Regulations.

3.0 EMISSION STANDARDS

For each facility or modification subject to construction permitting, the applicant must show that the proposed sources comply with State and federal emission standards. The Department has adopted federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs), by reference in 18 AAC 50.040. In addition, the Department has source-specific emission standards listed in 18 AAC 50.050-090.

3.1 NEW SOURCE PERFORMANCE STANDARDS

The U.S. Environmental Protection Agency promulgates and implements New Source Performance Standards (NSPS). The intent of NSPS is to provide technology-based emission control standards. EPA may delegate to each state the authority to implement and enforce standards of performance for new stationary sources located in that state. The Department has incorporated by reference the NSPS effective July 1, 1997, for specific industrial activities, as listed in 18 AAC 50.040. However, EPA has not delegated to the Department the authority to administer the NSPS program at this time.

The Dillingham Power Plant equipment subject to this permit decision includes sources that are affected facilities under NSPS. The two 500,000-gallon and one 850,000-gallon storage tanks are subject to NSPS Subpart Kb for volatile organic liquids storage vessels. All affected facilities must also comply with NSPS Subpart A general requirements, except as provided in Section Kb.

3.1.1 Subpart Kb: Volatile Organic Liquid Storage Tanks

Volatile organic liquid storage tanks greater than 40 cubic meters (m^3) in volume (10,567 gallons) are subject to this Subpart as listed in 40 CFR 60.110b(a). The two 500,000 gallon and one 850,000 gallon diesel-fuel storage tanks will be subject to Subpart Kb because tank capacity exceeds the 40-m^3 volume threshold and were installed after July 23, 1984. The tanks are exempt from the General Provisions (Part 60, Subpart A) as stated in 40 CFR 60.110b(c).

The Permittee is required to keep records under 40 CFR 60.116b(a) and (b), to keep readily accessible records showing the dimension of the storage vessels and an analysis showing the capacity of the storage vessel for each storage tank greater than or equal to 40 cubic meters. The Department has retained Permit Section 6 to ensure that affected facilities comply with the NSPS Subpart Kb.

3.2 NATIONAL EMISSION STANDARDS FOR HAZRDOUS AIR POLLUTANTS

The U.S. Environmental Protection Agency (EPA) promulgates National Emission Standards for Hazardous Air Pollutants (NESHAPs). 18 AAC 50.040 adopts the federal hazardous air pollutant regulations, 40 CFR 61, and 40 CFR 63, by reference. EPA may delegate to each state the authority to implement and enforce certain standards for sources located in that state. At this time, EPA has not delegated authority to the Department to administer the NESHAPs program. The applicant does not propose any new or modified sources subject to Federal NESHAPs.

3.3 ALASKA EMISSION STANDARDS

Industrial processes and fuel-burning equipment at the facility are subject to specific visible emission, particulate matter, and sulfur compound emission standards as listed in 18 AAC 50.055, open burning prohibitions as listed in 18 AAC 50.065, and fugitive dust prohibitions listed in 18 AAC 50.045(d). The Department has reviewed file documents and prepared monitoring, record keeping, and reporting requirements within the construction permit for compliance with the standards.

3.3.1 Visible Emissions

The industrial processes and fuel burning equipment at the Dillingham Power Plant are subject to a 20 percent visible emission standard as listed in 18 AAC 50.055(a)(1) and set out in Section 7, Condition 23.1. The Department has no record of any visible emission observations conducted by NEC or Department staff to demonstrate compliance, because the facility has never had an air quality permit. Therefore, NEC is required to verify compliance with the opacity standard by performing quarterly Visible Emission Surveillance tests for each source that operates greater than 100 unit-hours per calendar quarter as stated in Permit Condition 23.4(a). NEC must also conduct Visible Emission Surveillance tests upon the Department's request and report in accordance with Permit Section 8.

3.3.2 Particulate Matter

All fuel burning equipment at the Dillingham Power Plant are subject to a particulate matter standard of 0.05 grains per dry standard cubic foot of exhaust gas (gr/dscf), as listed in 18 AAC 50.055(b)(1), and set out in Section 7, Condition 23.2 of the permit. The applicant calculated the maximum short-term grain loading for all sources using emission factors provided by the vendor and AP-42, actual exhaust flow rates, and exit temperatures. The results can be seen below and are further described in Appendix A of this report.

Table 3.3-1: Particulate Matter Emissions

Source No.	PM Emission Rate	Reference	Grain Loading Results
Source No. 3	0.00220 lb/hp-hr	AP-42 Table 3.3-1	0.097 gr/dscf
Source No. 4	0.0007 lb/hp-hr	AP-42 Table 3.4-1	0.031 gr/dscf
Source No. 5	0.00070 lb/hp-hr	AP-42 Table 3.4-1	0.031 gr/dscf
Source No. 6	0.00070 lb/hp-hr	AP-42 Table 3.4-1	0.031 gr/dscf
Source No. 10	0.00031 lb/hp-hr	Vendor Specifications	0.015 gr/dscf

Sources No. 11, 12, 13	0.00035 lb/hp-hr	Vendor Specifications	0.021 gr/dscf

To estimate PM emissions from the small diesel engine (Source No. 3), NEC used an AP-42 emission factor. The analysis showed that using this emission factor, the small engine may emit greater than the 0.05 gr per dscf standard. This analysis does not necessarily suggest that the small engine is in violation of the particulate matter standard. The AP-42 emission factor used has a "D" rating, which indicates its reliability. A "D" rating implies that tests are based on a generally unacceptable method, but the method may provide an order-of-magnitude value for the source. Because the existing source is not subject to review under the construction permit for this project, the Department is not presently requiring NEC to demonstrate compliance with the standard. However, for future projects, it may be necessary for NEC to acquire a more accurate compliance demonstration in the application for determining PM emissions from a small diesel engine.

Based upon the analysis, the Department concurs that the sources should comply with the State emission standards for particulate matter, with exception to Source No. 3 as described above. However, NEC must conduct particulate matter source tests upon Department request and report in accordance with Permit Section 8.

3.3.3 Sulfur Compounds

All fuel-burning equipment are subject to the sulfur compound emission standard as set out in 18 AAC 50.055(c). Sulfur compound emissions from fuel-burning equipment, expressed as sulfur dioxide, may not exceed 500 ppm averaged over a period of three hours as set out in Permit Section 7, Condition 23.3.

All engines at the Dillingham Power Plant will burn diesel fuel. The applicant proposes to use distillate fuel oil with a sulfur content no greater than 0.50 percent by weight. The applicant demonstrated compliance with the sulfur compound emission standard for each source by calculating the short-term emission rate using the actual exhaust temperature and flow. The results are as shown below in Table 3.3-2 and further documented in Appendix A.

Table 3.3-2: Sulfur Compound Emissions

Source No.	SO_2 Emission Rate	Reference	Results
Source No. 3	0.218 g/s	Mass Balance	133 ppmv
Source No. 4	0.308 g/s	Mass Balance	131 ppmv
Source No. 5	0.463 g/s	Mass Balance	132 ppmv
Source No. 6	0.632 g/s	Mass Balance	135 ppmv
Source No. 10	0.709 g/s	Mass Balance	143 ppmv

Sources No. 11, 12, 13	0.642 g/s	Mass Balance	143 ppmv

Typically, fuel-burning equipment is operated with combustion air in excess of stoichiometric conditions to ensure fuel is completely burned under non-ideal conditions. This excess air dilutes exhaust gas concentrations of sulfur compounds. Accounting for excess air normal to a fuel-burning unit, the sources should comply with the sulfur compound limit while burning fuel with a sulfur content somewhat greater than 0.74 percent by weight.

The Department proposes to use limits, periodic monitoring, record keeping, and reporting requirements for fuel oil in Conditions 14 and 16, and Section 8 of the permit to ensure compliance with the sulfur compound standard.

3.3.4 Ice Fog Standards

The Department will, in its discretion, require a person who proposes to build or operate an industrial process, fuel-burning equipment, or incinerator in an area of potential ice fog to obtain a permit and to reduce water emissions. Ice fog is not a significant concern at the Dillingham Power Plant and emissions are not controlled with water-based technology. Therefore, the Department is not placing any additional conditions in the permit.

3.3.5 General Air Pollution Prohibited

18 AAC 50.110 and Permit Condition 24 state that no person may permit any emission that is injurious to human health or welfare, animal or plant life, or property, or that would unreasonably interfere with the enjoyment of life and property. The Department has proposed in Permit Conditions 24.1 and 24.2 that the applicant record all public complaints and take reasonable actions to correct air pollution complaints resulting from emissions at the facility. The Department has also proposed in Condition 10 that the applicant provide advanced notice of any modifications at the facility which would result in an increase in allowable emissions from the facility.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

The Department's goal for the best available control technology (BACT) review is to evaluate available technologies, identify BACT for the project's emission sources, and establish emission or operational limits which represent BACT. This review is conducted in accordance with State and federal rules and guidelines. In this section, the Department evaluates the available control technologies for each emission source and selects BACT. In addition, the Department assesses the level of monitoring, record keeping, and reporting necessary to ensure the applicant applies BACT.

Under the State of Alaska's PSD Provisions of the Air Quality Control Regulations, an applicant subject to pre-construction review must show that BACT will be installed and used for each new or modified source. BACT is defined as an emission limit that represents the maximum reduction achievable for each regulated air contaminant subject to pre-construction review under the PSD provisions of the Clean Air Act (CAA). For this project, BACT evaluation is required for the contaminant: oxides of nitrogen (NO_X).

Application of BACT must not result in emission of any pollutant which would exceed the emissions allowed by any applicable federal standard listed in 40 CFR, Part 60 NSPS, and 40 CFR 61, NESHAPs.

All BACT requirements, with limits, monitoring, record keeping, and reporting obligations are incorporated in Section 4 of the permit. Table 4.0-1 below summarizes the BACT limits proposed by the Department.

Table 4.0-1: Department BACT Limits

Equipment	Individual NO_X Limit
Sources No. 11, 12, and 13	24.9 lb/hr

Note: The NO_X BACT emission limit represents worst-case full-load operation. Actual emissions may be affected by the annual generation limits in the permit to protect ambient air quality and increments.

Standard for Making BACT Determinations

The methodology NEC used to identify BACT is the five-step "top-down" methodology set forth in the U.S. EPA's proposed *New Source Review Rule Revisions* (EPA 1990). EPA has published numerous policy memorandums and guidance documents to assist applicants and permitting authorities in using the top-down approach. In addition, there are some court cases and many administrative appeal decisions that further amplify and clarify the top-down approach.

The top-down approach was used to analyze the proposed BACT contained in the NEC Dillingham Power Plant construction permit application. Here is a description of the top-down process taken from EPA publications.

In step 1, the applicant identifies all available control options for the source and the pollutant under consideration. This includes technologies used throughout the world. To assist in identifying available controls, NEC and the Department reviewed the available controls listed on EPA's RACT/BACT/LAER (RBLC) Clearinghouse bulletin board where permitting agencies nationwide have listed the BACT control technologies imposed within the past five years.

In step 2, the applicant evaluates the technical feasibility of the various control options in relation to the specific source under consideration. If the applicant can clearly document and demonstrate, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option, it is eliminated from further consideration in this step.

In step 3, the remaining control options are listed in order of control effectiveness for the pollutant under review, with the most effective option at the top. In this step, the applicant also presents detailed information about the control efficiency, the expected emission rate, the expected emission reduction, and the cost, environmental, and energy impacts for each control option. An applicant proposing to use the most effective option is not required to provide the detailed information for the less effective options.

In step 4, the energy, environmental, and economic impacts are considered to arrive at the final level of control. The applicant is responsible for presenting an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts.

EPA's guidance describes the process for this step as follows: "If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts on other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT." The Department does not assess energy, environmental, or economical impacts of less stringent control strategies than that selected as BACT.

The process concludes in step 5, where the most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant and source under review.

4.1 BACT DETERMINATION FOR NO_X

The Dillingham Power Plant currently has the potential to emit greater than 250 tons per year of NOX, and is therefore classified as a PSD Major facility under 18 AAC 50.300(c)(1). According to 18 AAC 50.300(h)(3), any modification to a PSD major facility after August 7, 1980, that results in an increase of actual emissions greater than 40 tons per year of NOX, is subject to a BACT review for NOX. Because in 1980, the NEC Dillingham Power Plant had the potential to emit NOX greater than the PSD applicability threshold, the requirement is relevant to the facility's modifications subsequent to August 7, 1980.

In 1984, NEC installed two Caterpillar diesel-electric generators (Sources No. 8 and 9). The potential to emit from these engines was greater than the 40-tpy applicability threshold level for NO_X; thus, the change was a major modification. However, these sources were never evaluated for best available control technology (BACT) prior to installation, due to an incorrect oversight by the Department and the applicant in which the project was viewed as a minor modification. The Department recognized this error in February 1987. On March 3, 1998, during discussions with NEC regarding possible replacement of equipment, the Department and applicant agreed that existing Sources No. 8 and 9 would not have to undergo a BACT analysis as they were nearing the end of their useful life. However, future replacement sources would be required to install best available control technology.

NEC's permit action authorizes the installation and operation of three diesel-electric generators, Sources No. 11, 12, and 13, which replace existing Sources 4, 8, and 9. The replacement sources will each undergo a BACT analysis for NO_X.

The Department evaluated several NO_X control methods as BACT for the large diesel-fired engines. The specific options and an evaluation of results are summarized below, and discussed in detail in this section.

Table 4.1-1: Summary of NO_X BACT for Large Diesel-Fired IC Engines

Applicable Controls	Technically Feasible	Economically Feasible	BACT
Selective Catalytic Reduction	Yes	No	No
Non-Selective Catalytic Reduction	No	N/A	N/A
Selective Non-Catalytic Reduction	No	N/A	N/A
Fuel Injection Timing Retard	Yes	Yes	Yes
Electronic Fuel Injection	Yes	Yes	Yes
Turbocharger-Aftercooler	Yes	Yes	Yes
Derating	Yes	Yes	No
Humidity Control	No	N/A	N/A
Pre Chamber Design	No	N/A	N/A

Flue Gas Recirculation	No	N/A	N/A
Direct Water Injection	No	N/A	N/A
Good Combustion Management	Yes	Yes	Yes

4.1.1 Mechanisms of NO_X Formation

Combustion is defined as the rapid chemical combination of oxygen with combustible elements of a fuel. Combustion produces heat that can be manipulated to generate power. Most fuels have three combustible elements: carbon, hydrogen, and sulfur, which unite with oxygen from atmospheric air to produce heat. Atmospheric air is a mixture that contains roughly 79% nitrogen and 21% oxygen by volume. Nitrogen present in the combustion process sometimes combines with oxygen, forming oxides of nitrogen.

There are several types of oxides of nitrogen formed during the combustion process, but only two types occur in significant quantities: nitric oxide--NO, and nitrogen dioxide--NO_2. In stationary source combustion, most of the NO_X formed is nitric oxide (NO), which can oxidize in the atmosphere to form NO_2, a regulated air contaminant. At high temperatures, NO formation is favored almost exclusively over NO_2 formation, and the rate of NO_2 dissociation to NO is favored by the mechanism:

$$NO_2 + O + \text{heat} \leftrightarrow NO + O_2$$

After the flue gas exits the stack, the entrained NO may be oxidized by atmospheric ozone to form NO_2. Other complex atmospheric reactions with NO and NO_2 can also occur.

There are three mechanisms for NO_X formation during combustion of certain fossil fuels. These formation mechanisms are thermal, fuel-bound, and prompt NO_X. A brief discussion of each mechanism follows.

Thermal NO_X Formation

The predominant mechanism in combustion reactions is thermal fixation of the atmospheric nitrogen at elevated temperatures, usually greater than 2800□F, known as thermal NO_X. Production of thermal NO_X is an exponential function of the flame temperature, and a linear function of the time the hot gas mixture is at that flame temperature. This mechanism follows the Zeldovich reactions, with three predominant paths for NO_X formation in combustion:

$$(1)\ N_2 + O \leftrightarrow NO + N$$
$$(2)\ N + O_2 \leftrightarrow NO + O$$
$$(3)\ N + OH \leftrightarrow NO + H$$

Note that reaction (1), which is highly temperature-dependent, provides the atomic nitrogen (N) necessary for reactions (2) and (3). Note further that the reverse reactions are not favored by the presence of molecular oxygen. Therefore, in the oxidizing environment that normally prevails downstream from the actual combustion zone due to the presence of excess combustion air, the NO that has been formed is essentially fixed.

Fuel-Bound NO_X

Chemically-bound nitrogen in the fuel is known as fuel-bound nitrogen. The oxidation mechanism is dependent on fuel-bound nitrogen content, fuel properties, and the stoichiometric conditions present during combustion. The most significant factors attributing fuel-bound NO_X formation are chemically fuel-bound nitrogen content, and the fuel-to-air ratio during the early stages of combustion when fuel-bound nitrogen is liberated from the fuel.

As the chemically-bound nitrogen in the fuel enters the flame zone, the fuel is burned into small reactive, nitrogenous organic molecules which react with oxygen to form NO. In a reduction environment where insufficient oxygen is present for complete combustion, such as the fuel-rich zone of combustion, the nitrogenous fuel fragments encounter and react with each other, and convert the fuel-bound nitrogen to molecular nitrogen (N_2).

Fuel-bound nitrogen can be a significant source of NO_X emissions from fossil fuels such as residual oil and coal, but significantly less fuel-bound nitrogen is contained in natural gases. The Department typically uses the most conservative technique to estimate NO_X emissions due to fuel-bound nitrogen--to assume that all nitrogen in the fuel is converted to NO_X during combustion.

Prompt NO_X

Prompt NO_X is produced by the formation of an intermediary such as hydrogen cyanide (HCN), through the reaction of nitrogen radicals and hydrocarbons (HC),

$$NO + HC + H_2 \rightarrow HCN + H_2O$$

followed by the oxidation of the HCN to NO. The formation of prompt NO_X has a weak temperature dependence and a short lifetime of several microseconds. It is only significant in very fuel-rich flames, which are inherently low NO_X emitters.

4.1.2 NO_X Control Methods

This section describes the control technologies that may be available to reduce NO_X emissions from one or more of the source categories listed by the applicant. The Department's evaluation of the availability and effectiveness of these controls for the diesel-fired engines is provided in Section 4.1.3.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) is a potential emission control technology for turbines and other internal combustion sources. SCR systems use ammonia to selectively reduce NO_X to N_2. This technology reduces both thermal and fuel-bound NO_2. SCR injects ammonia or urea into the exhaust before the exhaust enters a catalyst bed made with vanadium, titanium, or platinum. The reduction reaction occurs when the flue gas passes over the catalyst bed where the NO_X and ammonia combine to become nitrogen, oxygen, and water as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The required catalyst bed temperature is dependent on the type of catalyst used, and must be maintained within a narrow temperature range for effectiveness. Manufacturers tailor their catalyst design for the temperature range expected. A metal oxide catalyst, such as vanadium or titanium is effective between approximately 600 °F and 750 °F. For a wider temperature range, zeolite catalysts have been effective in the 800 °F to 1200 °F temperature range.

Temperature dramatically affects NO_X reduction because the catalyst exhibits optimum performance within a narrow temperature range. Below this optimum range, the catalyst activity is greatly reduced, allowing unreacted ammonia to "slip" through. This slip results in increased ammonia concentration in the exhaust gas that is discharged into the atmosphere. Above the range, ammonia begins to be oxidized to form additional NO_X. Further excessive temperatures may damage the catalyst.

In addition to tight operating temperature controls, the SCR process requires good control and continual adjustment of the ammonia injection rate to match the rate of NO_X formation. An ammonia deficiency causes nitric oxide to react preferentially with the excess oxygen, while an ammonia surplus leads to additional ammonia slip.

Exposing a catalyst to sulfur-bearing fuels and ammonia forms ammonia salts. These salts foul the surface of the catalyst, rendering it useless and causing premature replacement. Sulfur-tolerant SCR catalysts are available, but are composed of vanadium pentoxide, a hazardous substance. These catalysts are still susceptible to some ammonium sulfate fouling. The spent vanadium pentoxide catalyst would have to be shipped off-site for disposal. To address this concern, many catalyst vendors operate exchange programs where spent catalysts are exchanged for new catalysts at a reduced price. Exchange programs alleviate customer waste disposal concerns and allow the vendor to recycle the precious metals that make up many of the catalysts.

In summary, successful operation of an SCR system occurs if the catalyst is exposed to an exhaust stream that is not an oxidizing environment. The injection of a reducing agent, most commonly ammonia (NH_3), causes NO to preferentially react with the agent to form nitrogen and water, rather than reacting with the excess oxygen. SCR requires a narrow temperature range to achieve optimum catalytic performance. SCR may be used in conjunction with reductions from steam or water injection, or combustion modifications.

Carefully designed SCR systems achieve NO_X reduction efficiencies as high as 90%, with ammonia slip vendor guarantees of no greater than 10 ppm available. Conservative reductions are 80% control efficiency. The Department has no clear evidence that the technology would be problematic in Alaska.

Non-Selective Catalytic Reduction (NSCR)

Non-selective Catalytic Reduction (NSCR), sometimes called a three-way catalyst, reduces NO_X emissions 80% to 90% at a temperature between 800 and 1200 degrees F. NSCR systems use a mixture of platinum and rhodium catalyst, and carbon monoxide and hydrocarbons (CH_4) as reducing agents contained in the flue gas, forming N_2, H_2O, and carbon dioxide. The chemical reaction process is not fully understood, but can be represented in the following basic formulas:

$$CH_4 + 4NO_2 \rightarrow CO_2 + 4NO + 2H_2O$$
$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$
$$CH_4 + 4NO_2 \rightarrow CO_2 + 2N_2 + 2H_2O$$
$$2CO + 2NO \rightarrow 2CO_2 + N_2$$
$$2H_2 + 2NO \rightarrow 2H_2O + N_2$$

NSCR is only effective in a fuel-rich, preferably gas-fired, non-variable load combustion. The air-to-fuel ratio must be at or close to stoichiometric to provide adequate concentration of reducing agents in the exhaust gas. Stoichiometric combustion produces exhaust gas nearly depleted of oxygen (less than four percent oxygen). The inability to control air-to-fuel ratio for varying loads limits NSCR application. NSCR is best known for its application in reducing NO_X from automobile exhaust. NSCR uses no reactant for the control of NO_X.

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a thermal denitrification process that also involves the injection of ammonia or urea into the exhaust gases. The ammonia or urea reduces NO_X to N_2 within a narrow temperature range of 1600 to 2000□F without a catalyst. At these temperatures, 80% to 90% NO_X emission reduction can be achieved. Since the optimum reaction temperature is very high, the applicability of SNCR can be restricted to large industrial boilers, unless supplemental heat is provided to the system by reclaiming a portion of the heat by a heat exchanger at the exhaust end of the reaction chamber.

As with SCR, SNCR may require transportation, handling, and storage of ammonia, a hazardous substance. In addition, there is a potential of ammonia slip in the exhaust gas, increasing ammonia levels in the ambient air. However, other reducing agents, such as urea, may be selected. The other technical problem for most applications is the physical ammonia or urea injection location. For equipment operating at various loads, the proper injection temperature "window" physically moves within the combustion zone and the exhaust ductwork. Therefore, a SNCR system may require multiple injection locations.

Direct Water Injection (DWI)

Direct Water Injection lowers the peak flame temperature by providing a heat sink that absorbs some of the heat of the reaction, thereby reducing peak flame temperature and the resultant rate of NO_X formation. The water injected into the engine is required to be extremely pure or the engine will require significant amounts of maintenance and repair.

Fuel Injection Timing Retard (FITR)

Fuel Injection Timing Retard (FITR) reduces NO_X emissions in reciprocating engines by delaying the injection of fuel in the engine from when the chamber is at its smallest, to a time when the compression chamber is expanding. The larger volume in the compression chamber produces a lower peak flame temperature, thus reducing thermal NO_X formation.

FITR reduces the fuel efficiency of engines and may lead to a potential increase in SO_2 emissions through increased fuel consumption. The extent of FITR is also limited because excessive injection delay can cause the engine to misfire. Emission reductions can range between 10% to 30% depending on the degree of FITR implemented.

Electronically Controlled Fuel Injection and Timing

Electronically controlled fuel injection is widely used on automobile engines, for optimizing the engine combustion variable to achieve good performance characteristics, while at the same time achieving low pollutant emissions. This technology allows the engine to perform at near-optimum combustion and emission control efficiency throughout the entire engine operating range, thereby providing a greatly enhanced ability to maintain optimum control of exhaust emissions. The electronic controls regulate the combustion process through control of fuel flow, air-to-fuel ratio, fuel injection timing and duration for diesel engines, and ignition timing for gasoline engines. Electronic-controlled emissions technology is available for some of the new large stationary diesel engines. However, extended research and development time is necessary before it can be applied to an existing or older engine model.

Turbocharger/Aftercooler

Turbocharging is used on large diesel engines to compress the intake air and increase the amount that can be charged to a cylinder, resulting in an increased intensity of combustion and engine efficiency. It also results in higher exhaust temperatures and higher NO_X emissions, because the average gas temperature over the cycle is increased. To reduce NO_X emissions, turbocharged intake air generally is cooled using an indirect-contact water heat exchanger, called an aftercooler. The cooler intake air results in lower peak combustion chamber temperatures and lower NO_X emissions in the engine's exhaust gases.

The turbocharger air temperature coming out of the aftercooler often can be further reduced on an existing engine installation by supplying additional cooling water to the aftercooler, or by installing a larger aftercooler. Modifying the aftercooler water circuit generally will require a separate radiator or heat exchanger to exhaust the heat to the ambient air or a water body.

However, not all engine models and makes can be modified to increase aftercooling because of their inherent design features.

Derating

Derating is operating of an engine below its rated capacity. Because less fuel is being burned, the engine runs at a cooler temperature and its resulting NO_X emissions are lower. However, derating directly reduces the facility's production capacity and is a feasible NO_X strategy only when a facility has more installed capacity than it needs. In addition, this reduction of NO_X is not achieved without an offsetting air quality price tag in the form of increased SO_2, CO, PM_{10}, and VOC emission rates.

Humidity Control

Another possible approach to reduce thermal NO_X formation in reciprocating engines is to humidify the intake air allowing a limited amount of water into the combustion chamber. The humidified air acts as a heat sink to reduce the flame zone temperature in the combustion chamber, which theoretically reduces the amount of NO_X formed. A demonstration project for intake air humidification used air constantly humidified to 90-95% relative humidity. However, the source test results indicate an insignificant reduction in NO_X and an increased amount of unburned hydrocarbon emissions. Early experiments evaluated water or steam injection as an alternative approach. However, the direct injection of water/steam produced hot spots on the cylinder head and valves, misfiring, knocking, and catastrophic crankshaft failures.

Flue Gas Recirculation (FGR)

The basic principal of flue gas recirculation (FGR) is to replace a portion of the incoming combustion air with exhaust gas. FGR reduces NOX formation by reducing the available oxygen content and by acting as a heat sink to lower peak combustion temperatures. At full-load, this results in a richer burn with more exhaust gas to absorb the heat of combustion, resulting in a lower combustion temperature. NOX removal of up to 40% is achievable by using a maximum recirculation of 30% exhaust gas.

FGR has been commercially used in spark-ignition gas engines and some industrial boilers, but not in large diesel engine applications. Applying an FGR system to an existing diesel engine would require complex engineering design work, and a control and monitoring system. FGR can be expected to become more practical with stationary diesel engines after particulate traps are more fully developed. Excessive particulate matter in the recirculated exhaust can cause substantial problems in the combustion chamber. Recirculated flue gas may cause decreased engine efficiency, increased CO emissions, misfire, and potential on-line reliability problems.

Pre Chamber Design

In a pre chamber design, air and fuel are injected directly in the combustion zone to mix and combust simultaneously. The off-stoichiometric or staged combustion air method separates the combustion process into two stages: primary and secondary combustion. Primary combustion is the first stage of combustion conducted in a fuel-rich combustion zone. Combustion is then completed at lower temperatures in a secondary, fuel-lean zone.

The fuel-rich first stage inhibits the formation of thermal NO_X as insufficient oxygen levels prevent complete combustion. Second stage combustion temperatures are below peak thermal NO_X formation temperatures due to the injection of excess air. This design controls both thermal and fuel NO_X. Low NO_X burners (LNB) achieve reductions in NO_X emissions by using multiple combustion stages with varying fuel-air ratios to reduce combustion temperatures and thermal NO_X formation.

Good Combustion Management

Good combustion management is applicable for all combustion sources. This method requires operating and maintaining the equipment according to the manufacturer's recommendations, operator experience, and good engineering practices to obtain maximum fuel efficiency and minimum emissions.

4.1.3 NO_X BACT Analysis for Diesel Electric Generators, Sources No. 11, 12, and 13

NEC currently operates seven diesel-electric generator sets (Sources No. 3, 4, 5, 6, 8, 9, and 10) at the Dillingham Power Plant. In this permit action, NEC proposes to replace Sources 4, 8, and 9 with three 1,050 ekW Caterpillar #3512B slow-speed diesel-electric generators (Sources 11, 12, and 13). Each replacement engine is subject to BACT review for NO_X in this construction permit process.

The following presents the Department's final BACT review using the step-by-step top-down approach described previously. Because the replacement engines are identical, the steps are analogous for all sources.

Step 1 – Identify All Control Technologies

The sources under review are three 1,050 ekW Caterpillar #3512B Slow-Speed Diesel Electric Generators (Sources No. 11, 12, and 13).

The applicant identified twelve control technologies for control of NO_X that are applicable to these sources. The technologies are Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Non-Selective Catalytic Reduction (NSCR), Fuel Injection Timing Retard (FITR), Electronic Fuel Injection, Turbocharger/Aftercooler Systems, Pre Chamber Design, Direct Water Injection (DWI), Flue Gas Recirculation (FGR), Humidity Control, Derating, and Good Combustion Management.

In general, the Department concurs with the applicant's identification of applicable control technologies.

Step 2 – Eliminate the Technically Infeasible Options

The applicant eliminated from consideration the following six technically-infeasible control technologies. Both flue gas recirculation (FGR) and direct water injection (DWI) are mechanically complex systems which have been utilized in research and demonstration programs, but are not commercially available for the diesel-electric generation sets proposed for use at the Dillingham Power Plant. Non-Selective Catalytic Reduction (NSCR) is not applicable to lean combustion engines because the oxygen content of the exhaust gas is too high. Selective Non-Catalytic Reduction (SNCR) is not applicable at the temperatures expected in the exhaust gas manifold of the engines. Humidification is inapplicable in regions such as Dillingham because of low ambient temperatures and high relative humidity of the ambient air, creating little room for increased reduction of NO_X through humidification. Pre Chamber Design is a control option intrinsic to the original engine design. The engines NEC is proposing as BACT do not have a pre chamber design, yet are more stringent than a standard engine with a pre chamber design. For that reason, the Department will not continue to address the pre chamber design control option in this BACT review process.

The collateral impact clause of the BACT definition allows permitting authorities to temper the stringency of BACT in cases where the energy, environmental, or economic impacts that are associated with the use of a control option at a specific facility are viewed by the review agency as sufficiently adverse as to render the use of that technology inappropriate for a given facility.

Because Dillingham is isolated from other utility power generation systems, all of the power generated by the NEC facility must be used to meet the demand of its residential and commercial customers. If NEC derates the three replacement engines, the existing diesel engines will have to increase in operation in order to satisfy the power demand. In this scenario, emissions of all pollutants would potentially increase as NEC would need to run the older, less efficient machines to produce adequate power. Therefore, the applicant is not considering derating as a potential BACT option due to environmental constraints.

The Department reviewed and concurred with these findings.

Step 3 – Rank the Remaining Control Technologies by Control Effectiveness

A ranking for Sources No. 11, 12, and 13 by control effectiveness, expressed as percent reduction in NO_X from the base case and emission in tons per year after application of the control option, is shown below in Table 4.1-2. For this analysis, the base case scenario is a standard 1,050 ekW Caterpillar #3512 Diesel Engine.

The remaining feasible control technologies are: (1) selective catalytic reduction with a lean-burn/low NO_X engine design; (2) selective catalytic reduction; (3) a lean-burn/low NO_X engine design; and (4) the base case engine design all operating under good combustion management. The technologies incorporated in the lean-burn/low NO_X engine design are explained below.

Table 4.1-2: NO_X Control Effectiveness for Sources No. 11, 12, and 13

No.	Control Option for Sources No. 11, 12, 13	Emission Rate (tpy)	Percent Reduction (%)
1	Selective Catalytic Reduction w/ a Lean Burn/Low NO_X Design	16.9	87.5
2	Selective Catalytic Reduction	27.1	80.0
3	Lean Burn/Low NO_X Design	84.6	37.6
4	Base Case	135.6	--

Note: The applicant's assessment used projected actuals at 85% load and 8000 hours of operation per year to get more precise results. This differs slightly from the permit limit representative of 7,000,000 ekW-hr per year for each engine. See Appendix B for calculations.

The lean-burn/low NO_X engine design option is a 1,050 ekW Caterpillar #3512B Slow-Speed Diesel Engine set in a low emission strategy. This lean burn/low NO_X engine comes equipped with a turbocharger/aftercooling system with a separate aftercooler loop and electronically controlled fuel injection and timing as discussed below.

The engine is exhaust turbo charged and provided with an aftercooler core plumbed on a separate cooling loop, rather than the standard plumbing/configuration which combines the aftercooler with the jacket water and oil cooler circuit. This modified strategy allows NEC the ability to run the aftercooler at about 130°F or cooler, rather than 170°F typical when the aftercooler is combined with the jacket water and oil cooling loop.

The electronic fuel injection controls are computer controlled to balance combustion and achieve optimization of emissions through fuel injection timing, air-to-fuel-ratio, and duration of fuel injection. The priority of the computer control program may be set for minimum emissions or for maximum fuel efficiency. This is called the "low NO_X emission strategy" or the "low brake specific fuel consumption strategy". The proposed engine design would be set for low NO_X emissions.

In addition to computer controlled direct fuel injection, the new 3512B also provides other significant performance improvements which reduce emissions and improve fuel efficiency, including: revised piston crown and head, and higher injection pressures.

The applicant provided detailed discussion of the economic, environmental, and energy impacts for these control options in the application and addenda. See Appendix B for calculations and a summary of prices and percent reductions for each option.

Step 4 – Evaluate the Most Effective Controls and Document Results

The most effective control applicable to NEC's Sources No. 11, 12, and 13 is Option 1, Selective Catalytic Reduction with the Lean-Burn/Low NO_X engine design, as shown above with an 87.5% reduction of NO_X.

The capital cost to install this control technology is estimated at $602,600, with an annual operating cost of approximately $148,900. This translates to a cost-effectiveness of $1,976 per ton of NO_X removed (see Appendix B).

As previously indicated, the collateral impact clause of the BACT definition allows permitting authorities to temper the stringency of BACT in cases where the energy, environmental, or economic impacts that are associated with the use of a control option at a specific facility are viewed by the review agency as sufficiently adverse as to render the use of that technology inappropriate for a given facility.

Because the Dillingham Power Plant is a publicly-owned utility, there is no group of investors making a profit on the sale of electricity to customers. Therefore, the applicant concludes that the Department should reject Option 1 due to economic considerations, as the increased costs per kilowatt hour produced are very significant, ultimately affecting NEC's 1,374 customers which have no alternative power source. The results of requiring control Option 1 would increase the projected electrical power cost of the specific unit by 27.0% when compared with the average 1998 facility costs of 11.6¢ per kilowatt-hour.

The Department concurred with NEC and thought it appropriate that a BACT analysis of a small publicly owned non-profit facility consider not only the cost per ton of pollutant removed, but also the cost per kilowatt-hour increase affecting each customer. Therefore, in the Department's judgement, a 27.0% electrical power cost increase associated with controls on a unit basis is excessive (from 11.6¢ to 14.9¢ per kilowatt-hour).

The next most effective control for the top-down BACT approach is control Option 2, Selective Catalytic Reduction, as shown above, with an 80% reduction of NO_X emissions.

The capital cost to install this technology is estimated at $552,600, with an annual operating cost of $141,000. This translates to a cost-effectiveness of $2,019 per ton of NO_X removed with an increased electrical power cost on a unit bases of 21.4% (see Appendix B, Table B-1).

Based on the same argument used for Option 1, the applicant proposes that the Department reject Option 2 due to economic impacts ultimately affecting NEC's 1,374 customers.

The Department agrees with NEC and concludes that a 21.4% electrical power cost increase associated with control Option 2 would also constitute a disproportionate cost to consumers (from 11.6¢ to 14.0¢ per kilowatt-hour).

NO_X BACT Decision for Sources No. 11, 12, and 13

The Department finds that an emission rate achievable with the Lean-Burn/Low NO_X engine design operating under Good Combustion Management (Option 3) to be BACT on diesel generators Sources No. 11, 12, and 13. As previously described, this control technology comes equipped with a turbocharger/aftercooling system with a separate aftercooler loop and electronically controlled fuel injection and timing. A full load emission rate of 24.9 lb/hour is representative of the 37.6% NO_X reduction expected with this selected BACT option. However, actual NO_X emissions may be affected by the annual power generation limits requested by the applicant to protect ambient air quality and increments.

The increased capital cost to buy one lean-burn/low NO_X engine design in lieu of the normal engine configuration is estimated at $50,000, with an annual operating cost of approximately $24,400 per engine. This translates to a cost-effectiveness of $620 per ton of NO_X removed and only a 3.1% power cost increase associated with operation of one engine.

Condition 17.1(a) of the permit requires the three replacement engines to meet the 24.9 lb/hour NO_X limit representative of BACT. Condition 17.1(b) requires source testing of each engine no later than 6 months after initial startup to demonstrate compliance with the BACT requirement. The results must be reported as indicated in permit Section 8.

NO_X BACT Analysis Conclusion for Sources No. 11, 12, and 13

The Department's BACT analysis for NO_X on Sources 11, 12, and 13 found that selective catalytic reduction was not best available control technologies for the Dillingham Power Plant.

This decision was based on unusual circumstances that justify the examination of economic criteria other than costs-per-ton of pollutant removed. The criteria considered in this analysis were (1) the Dillingham Power Plant is a small publicly owned non-profit facility;
(2) Dillingham is not connected to the nationwide electric grid; (3) NEC customers currently pay approximately 40% more per kilowatt-hour than the national average cost of electricity (11.6¢/ekW-hr versus 8.45 ¢/ekW-hr); and (4) severe impacts on the cost of production of electricity are directly related to the cost increases for customers. Therefore, the Department's economic analysis included not only determining the cost-per-ton of pollutant removed, but also the increase in cost per kilowatt-hour associated with the control technology.

The selective catalytic reduction results of the BACT analysis (Options 1 and 2) demonstrated extreme cost of production increases, from 21.4% to 27.0% above the average cost of operation per engine. The overall facility effects of installing these control technologies on all three engines would result in production cost increases from 21.8% to 23.3% and hence, the customers cost would most likely increase accordingly.

In conclusion, the Department concurs with NEC that the costs associated with selective catalytic reduction would adversely affect the customers. Therefore, the lean-burn/low NO_X option selected is economically justified as best available control technology.

5.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

The Department's goal for the ambient air quality review is to determine whether the proposed increase in emissions will cause or contribute to a violation of an ambient air quality standard established in 18 AAC 50.010, or an air quality increment established in 18 AAC 50.020(b)(2). The air quality standards were set by the U.S. Environmental Protection Agency (EPA) and the Department to protect human health and welfare. EPA established the increments to prevent significant deterioration of air quality in areas that meet ambient air quality standards.

In this section, the Department outlines the planning tools used to review ambient impacts associated with the proposed project, the project analysis, and results. In addition, the Department assesses the need for ambient air contaminant monitoring after the project is constructed.

5.1 STANDARDS, INCREMENTS, AND AMBIENT ANALYSIS TOOLS

The following discussion provides background information regarding the national ambient air quality standards, PSD increments and area classifications, and the methods available to assess ambient impacts.

5.1.1 National Ambient Air Quality Standards

Ambient air is air external to buildings to which the public has access. Ambient air does not include indoor air and does not include air within the fence-line of an industrial complex, facility, or workplace. EPA has developed National Ambient Air Quality Standards (NAAQS) to protect public health and welfare for the following air contaminants: sulfur dioxide (SO_2), ozone, particulate matter, nitrogen dioxide (NO_2), carbon monoxide (CO), and lead. In July 1997, EPA revised the ambient standard for particulate matter smaller than 10 microns in diameter (PM-10), and established a new ambient standard for particulate matter smaller than 2.5 microns in diameter (PM-2.5).[7] The Alaska Ambient Air Quality Standards (AAAQS) reflect the pre-1997 NAAQS, along with ambient standards for ammonia and reduced sulfur compounds. The AAAQS are listed in the Air Quality Control Regulations under 18 AAC 50.010.

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[7] The revised federal PM-10 and PM-2.5 standards became effective September 16, 1997. However, EPA is still developing the tools needed to predict PM-2.5 ambient impacts from proposed sources, and has not yet established PM-2.5 thresholds for PSD permitting. According to an October 24, 1997 EPA Memorandum, "EPA believes that it is administratively impracticable at this time to require sources and State permitting authorities to attempt to implement PSD permitting for PM-2.5" (EPA 1997b). In the meantime, EPA is using PM-10 modeling as a surrogate for the PM-2.5 analysis in meeting the new source review requirements under the Clean Air Act. EPA is also developing revisions to their *Guideline on Air Quality Models* regarding the modeling of the revised PM-10 standard.

Air quality at the workplace is regulated through standards developed for worker safety and health, and enforced by the Department of Labor and the Federal Occupational Health and Safety Administration. EPA regulates indoor air in programs not delegated to the Department.

5.1.2 PSD Increments

In 1977, Congress established a classification system to control new air contaminant emission sources. Congress mandated that EPA protect air quality in areas with good air quality by establishing the maximum level to which air contaminant concentrations could increase in ambient air. Increments are developed by EPA to allow some industrial growth, while limiting deterioration of air quality. EPA has promulgated increments for NO_2, SO_2, and PM-10.[8]

The Prevention of Significant Deterioration Program (PSD) sets baseline dates from which to measure growth. The baseline date is set for a given air contaminant in a given region, when the Department receives a complete Air Quality Permit application for a major project subject to pre-construction review under PSD. Subsequent to the baseline date, all cumulative increases in ambient air concentration must remain below the increment.

For the purposes of PSD, Alaska is divided into four Intrastate Ambient Air Quality Regions: No. 008--Cook Inlet Intrastate Region; No. 009--Northern Alaska Intrastate Region; No. 010--Southcentral Alaska Intrastate Region; and No. 011--Southeastern Alaska Intrastate Region. The applicant's facility is located in the Southcentral Intrastate Region. Baseline dates have been set in the Southcentral Intrastate Region for all three pollutants with ambient increments: SO_2, NO_2, and PM-10.

Congress also established three classes of areas in attainment with the NAAQS: Class I, typically for National Parks and National Wildlife Refuges, which allows new emissions to only use up about ten percent of the NAAQS and nearly precludes any industrial growth; Class III, for industrial areas which allows growth to use up to 50% of the NAAQS; and Class II for all other areas, which allows moderate growth, but assures that growth does not use up more than about 25% of the NAAQS.

Congress established four Class I areas in Alaska: that portion of Denali National Park and Preserve encompassing the boundaries of the former Mt. McKinley National Park, Tuxedni Wilderness Area, Bering Sea Wilderness Area, and Simeonof Wilderness Area. Not only are Class I areas subject to stringent increments, the areas' air resources are protected by Visibility and Integral Vista Provisions of the Clean Air Act, as discussed in Section 6.1.1.

The remainder of Alaska is classified as Class II, which allows moderate development. Alaska has no Class III areas. Dillingham is located within a Class II area.

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[8] The PM-10 increments are based on the pre-1997 ambient air quality standard. EPA has not yet revised the New Source Review program, including PSD increments, subsequent to the 1997 PM-10/PM-2.5 NAAQS rulemaking.

5.1.3 Ambient Analysis Tools

An applicant for pre-construction review under PSD Provisions may be required to include in their application meteorological data, pre-construction ambient air contaminant data, and a computerized dispersion modeling assessment. These three components are used as ambient analysis tools to ensure the planned project complies with the AAAQS and PSD increments.

Computer dispersion simulation modeling is used as a planning tool to predict ambient air quality impacts. Ambient air contaminant concentrations are dependent on emission rates due to a given project or facility, emission stack parameters, weather conditions, and terrain, as well as background levels of contaminants. EPA has developed specific models to predict these impacts. The models require emission rates, plume flow rates and exit temperatures, stack height, building dimensions, and locations and elevations for the receptors that modelers wish to assess impacts. Models also use default worst-case meteorological parameters or actual meteorological data, depending on their level of sophistication.

NEC presented past allowable emissions and the proposed net emission increases for all regulated pollutants in Tables 3-1 and 3-2 of the January 1999 application. These emissions were then compared to the PSD-significant emission thresholds, and only those regulated pollutants that exceeded those thresholds were analyzed for potential ambient air impacts. The proposed modification will result in a net emission rate increase that exceeds the significant emission rate for the pollutant NO_2. Therefore, this pollutant will undergo a complete air quality analysis. Although the proposed project did not exceed the 40-ton-per-year threshold for SO_2, the applicant did conduct an ambient impact analysis for this pollutant.

NEC used modeling and existing monitoring data to demonstrate that the proposed project emissions will *not* cause or contribute to a violation of the NO_2 and SO_2 AAAQS. NEC used these same tools to demonstrate that the proposed modifications will *not* cause or contribute to a violation of the NO_2 and SO_2 increments. The following sections describe the meteorological data, ambient air contaminant data, and modeling analysis in further detail.

5.2 METEOROLOGICAL DATA

ISCST3, the computer model used by the applicant, requires representative hourly meteorological data to estimate plume dispersion. According to EPA's *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W), the meteorological data set should consist of at least one year of site-specific data or at least five years of area-wide meteorological data.

The NWS station is located two (2) kilometers (km) west of the power plant. The modeling protocol for this project proposed to use five years of data for both short- and long-term pollutant averaging periods. However, review of the data by NEC determined it was not able to meet recommended data capture rates of 90 percent or more in each sampling month. The protocol proposed a data substitution methodology that the Department and EPA Region 10 recommended be modified to include multiple stability substitutions for the missing early morning hours of each year. This resulted in two missing stability scenarios that bound the range of possible stability data. The meteorological data were collected between 1991 and 1997.

The Department analyzed information on the proximity of the meteorological station to the NEC project and the lack of significant topographic features between the monitoring station and the power plant. This analysis allowed the Department to make a determination that the Dillingham NWS meteorological data is representative of the ambient air flow conditions at the Dillingham Power Plant. The Department has used this information to accept these data in NEC's ambient modeling demonstration.

NEC used seven years of surface and upper air meteorological data collected by the National Weather Service (NWS) at the Dillingham airport. With the use of seven years of data, the Department allowed NEC to use the high second-high modeled concentration for comparison to the short-term ambient air quality standards and increments.

The finding of no significant topographic features between the power plant and general closeness to the power plant, allowed for the use of less than five years of meteorological data. The NWS station was found to be more representative of an on-site station for this project. Therefore, the modeling of annual average concentrations were based on the use of the three years of airport data that had a greater than 90 percent data capture. As discussed in detail in later sections of this document, the predicted project impact to an annual ambient air standard was determined to be insignificant. This finding diminished any uncertainty that a worst-case ambient air impact assessment from this three years of NWS data had not been conducted for this proposed modification.

5.3 AMBIENT AIR CONTAMINANT MONITORING

18 AAC 50.310(d) requires PSD applicants to submit ambient air quality data describing the air quality in the vicinity of the proposed project. This data must be developed unless the existing ambient concentration or the computer model-predicted ambient impact for the proposal is less than the thresholds provided in 18 AAC 50.310(e). In the past, the Department has occasionally accepted ambient data from other remote locations. Ambient data is also needed to provide the background concentration, which is added to the modeled concentrations to provide an estimate of the total ambient impact from the proposed project.

18 AAC 50.310(n) requires a demonstration that the proposed allowable emissions from the facility will not interfere with the attainment or maintenance of the ambient air quality standard or the maximum allowable ambient increment. Although the proposed modification is for less than 40 tons per year of SO_2 emissions, NEC provided an ambient air analysis to comply with Section, 18 AAC 50.310(n).

5.3.1 Pre-Construction Monitoring

A proposed new facility that is a major source under the PSD regulations is required to evaluate existing air quality levels in the vicinity of the proposed site for those pollutants with PSD-significant emission rates. NEC is a modification to an existing major facility because the proposed NO_X emissions will exceed the PSD-significant threshold of 40 tons per year. Therefore, only an analysis of the NO_X emission increase on the NO_2 NAAQS and increment in excess of this 40-ton-limit is required. If representative ambient air quality data are not available, the applicant must evaluate whether the existing air quality or modeled impacts from the proposed source require pre-construction air quality monitoring. De minimus monitoring impact levels listed in 18 AAC 50.310(e) define the air quality thresholds for pre-construction monitoring. The net NO_2 emissions increase was modeled by NEC and the maximum NO_2 impact was determined using the national Ambient Ratio Method (ARM) adjustment factor of 0.75 (ARM is discussed in Section 5.4.2).

The results of the modeling analysis are provided below in Table 5.3-1, along with the thresholds from 18 AAC 50.310(e). The proposed project does not exceed the thresholds for NO_2. Therefore, NEC did not have to conduct pre-construction monitoring for NO_2.

Table 5.3-1: Modeled Impacts vs. Pre-Construction Monitoring Thresholds

Pollutant	Averaging Period	Modeled Impact from Proposal (µg/m³)	Pre-Construction Monitoring Threshold (µg/m³)
NO_2	Annual	8.3	14

5.3.2 Background Concentrations

To the Department's knowledge, no one has measured actual ambient air pollutant concentrations in Dillingham. The only significant local point sources are the power plant, Peter Pan, and Dragnet Fisheries (Dragnet). Therefore, NEC used measured ambient air background data from another remote area as a surrogate for ambient background concentration(s) in Dillingham. NEC compared ambient concentrations measured near the Tesoro refinery (1981-82), Unalaska (Pyramid Valley), and by the Healy Clean Coal Project (HCCP) near Denali National Park and Preserve. The highest of these values was used by NEC as the ambient pollutant background concentration in Dillingham. The ambient data for these locations, and the assumed background concentration are provided below in Table 5.3-2.

The Department researched ambient NO_2 data for other rural areas of the state and found a monitoring site that more accurately accounts for area sources in a commercial fishing area. That data is from the second Unalaska ambient air station operated for the post-construction monitoring project at the American President Line's (APL) site. The Department accepts the APL maximum ambient NO_2 value as a better representation of ambient background concentrations in the marine and commercial fishing environment in Dillingham. This data has been incorporated into Table 5.3.2 below.

Table 5.3-2: Monitored Background Concentrations at Rural Alaskan Locations

Pollutant	Averaging	Ambient Concentration (µg/m³)	Selected Bkgd.

	Period	Unalaska, American President Line	Tesoro	Unalaska, Pyramid Valley	HCCP	Conc. (μg/m³)
NO_2	Annual	18.6	2.0	2.0	6	18.6
SO_2	3-hr	N/A	N/A	N/A	44	44
	24-hr	N/A	N/A	N/A	26	26
	Annual	N/A	N/A	N/A	5	5
PM-10	24-hr	N/A	N/A	N/A	31	31
	Annual	N/A	N/A	N/A	5	5

5.4 DISPERSION MODELING

NEC used computer analysis to predict the NO_2, and SO_2 ambient air quality impacts from the emission sources listed in their permit application. The computer analysis (modeling) of the modified NEC power plant was conducted by Steigers Corporation. This section describes which model was selected, how the analysis was conducted, and the final results of the analysis.

5.4.1 Model Selection

EPA has developed several computer models to estimate ambient air quality impacts from pollution sources. These models are listed in Appendix W of 40 CFR Part 51. The models differ by how they treat various sources, whether or not they need actual weather data, and how they handle terrain features that rise above plume height. They are classified as screening, refined, simple terrain, and complex terrain models. Screening models use generic weather conditions to provide conservative estimates. Refined models require actual weather data to provide more precise estimates. Complex terrain models typically provide the best estimates at ambient sites (receptors) that are above a source's stacks. Simple terrain models predict ambient impacts at sites below a source's stacks.

Steigers Corporation used EPA's *Industrial Source Complex Version 3* (ISC3) model for the ambient analysis. ISC3 is the refined computer model typically used to estimate the ambient air quality impact from industrial facilities. It requires historic weather data and is designed to estimate ambient concentrations from numerous emission sources at different locations. ISC3 is a simple and complex terrain computer model. EPA's intermediate terrain policy is defined in the June 8, 1989 memorandum by Joseph A. Tikvart. This policy defines three terrain areas: 1) simple terrain as those receptor locations with elevation below stack top; 2) intermediate terrain as those receptor locations with elevations between the top of the stack and the height of the plume; and 3) complex terrain as those receptor locations with elevations greater than the plume height. ISC3 incorporates the computer code from the COMPLEX1 complex terrain model and calculates ambient concentrations in simple, intermediate, and complex terrain following EPA guidance. ISC3 can also estimate the effects of downwash due to eddies that form around nearby buildings. Because the model uses hourly weather data to calculate an hourly concentration, it is able to average concentrations over the 3-hour, 8-hour, 24-hour, and annual periods upon which ambient standards and increments are based.

EPA is continually improving their computer models to better estimate ambient air impacts. Therefore, each model has a version number representing the year and calendar date of its release. Steigers Corporation used ISC3, version 96113. This was the current version of ISC available when NEC submitted their January 1999 application, and is appropriate for this analysis. The rural option of the ISC3 model was used in addition to the regulatory default switch. This ensured all model options were in conformance to EPA modeling guidance. The Department concurred with this approach and the version of the model used for this ambient analysis.

5.4.2 Approach

This section describes how the modeling analysis was conducted.

Modeled Scenarios

NEC is proposing to install and operate three new 3512B Caterpillar diesel-generators, Sources 11, 12, and 13, at their existing Dillingham Power Plant. To help offset the impacts from these new sources, NEC is proposing to retire Sources 4, 8, and 9, and increase the stack heights for all remaining sources.

Two facility configurations were considered by NEC for the replacement of the engines. Configuration 1 analyzes the addition of a new low-NO_X emitting engine (Source 11) and retirement of Source 4. Configuration 2 analyzes the replacement of Sources 8 and 9 with low-NO_X emitting engines (Sources 12 and 13) that are identical to Source 11.

The Department reviewed the modeling analysis associated with the proposal to add the three new Caterpillar generators and increase the stack heights. The results provided in this report represent what are assumed to be worst-case impacts. Section 6.2.3 of the construction permit application explains in detail how the applicant's baseline and PSD increment-consuming sources were modeled for the PSD increment analysis.

General Input Data

In addition to meteorological data or assumptions, ambient concentrations are dependent on the amount of pollution released, and on the emission (plume) characteristics. In general, plumes that are relatively hot will rise higher in the atmosphere and disperse better than cooler plumes. In the same manner, plumes that leave stacks at relatively fast flow rates tend to initially rise higher in the atmosphere and disperse better than slow plumes. Therefore, computer modeling requires specific information concerning emission rates, stack heights and diameters, exhaust flow rates and temperatures, and relative source locations.

The stack temperature and exhaust flow rates used by NEC are based on manufacturer's data, that were provided in the application. The assumed source characteristics such as stack heights and diameters, are also provided in the application.

SO_2 emissions are directly related to the amount of sulfur in the fuel. NEC will burn diesel fuel at the power plant and use a fuel sulfur level of 0.50 percent by weight. This fuel quality was used for the modeling analysis. The 0.50 percent by weight sulfur level will be included in the permit, as well as a ton per 12-month rolling total emission limit to prevent an exceedance of the PSD Pre-Construction review threshold for this pollutant.

Part-Load Analysis

The maximum ambient concentrations do not always occur during the full-load conditions that typically produce the largest emissions. The relatively poor dispersion that occurs with cooler exhaust temperatures and slower part-load exit velocities may produce the maximum ambient impacts. Therefore, EPA recommends that part-load conditions be analyzed as well as full-load conditions.

To address part-load concerns, NEC modeled ambient impacts at full-load, 75-percent load, and 50-percent load conditions. The maximum impacts presented in this Technical Analysis Report represent the maximum concentration from any of the evaluated load conditions. For this application, the reduced load condition of eighty-three percent (83%) load represented the worst-case scenario for the annual impact assessment. This value more accurately represented the operational characteristics for this facility, as NEC may utilize waste heat boilers in the wintertime. The 100 percent load condition was determined to represent the worst-case ambient impact scenario for the short-term assessment.

Downwash

Downwash refers to conditions where wind washes the plume down to the ground due to eddies that form down-wind of buildings or other obstructions. Downwash can occur when a stack height is less than a height derived by a procedure called Good Engineering Practice (GEP), as defined in 18 AAC 50.910(43). The NEC stack heights are lower than the minimum allowable GEP of 65 meters. Therefore, they are fully creditable. However, all stacks are within the influence of nearby buildings as they are all lower than 1.5 Length + Height test for downwash influence from nearby buildings. This finding required the use of the down-wash option in the ISCST3 computer model.

The modeling of downwash impacts requires the inclusion of dimensions from nearby buildings. EPA has established specific algorithms for determining which buildings must be included and for determining the profile dimensions that would affect a given stack. They have also incorporated these algorithms in a separate computer program called the Building Profile Input Program (BPIP).

NEC used BPIP (version 95086) to determine the needed building profiles for use with ISCST3 for the proposal and the Source stack upgrades. This is the current version of BPIP, and is appropriate for this analysis.

Land Classification

Steigers Corporation classified the region surrounding Dillingham as rural land use. Therefore, ISCST3 was set to use the rural dispersion coefficients. The Department concurs with this assessment.

Terrain

Dillingham is in an area where there is some variation in terrain elevation. However, the immediate area near the plant would be classified as simple terrain for ambient modeling, as the ground-based receptor locations will be below the modified stack heights for this project. Some elevated terrain exits several kilometers from the power plant, and NEC included these terrain features in their modeling analysis. Details on terrain and the ISC3 model application for simple and complex terrain are found in previous sections. The inclusion of these terrain features is appropriate.

Receptor Grid

ISC3 will predict ambient impacts at specific receptors identified by the modeler. These receptors are typically placed in a grid surrounding the facility, with a spacing agreed upon by the applicant and permitting agency.

NEC used several receptor grids. The NEC receptor grid consisted of the following:

1. 25-meter spacing around the facility boundary;
2. 50-meter spacing extending from the power plant boundary to 700 meters;
3. 100-meter spacing between distances of 700 and 1,200 meters from the facility boundary;
4. 250-meter spacing between distances of 1,200 and 3,000 meters from facility boundary, and
5. 1-km spacing between distances of 3 and 10 km from the power plant boundary.

Ambient NO_2 Modeling

NO_X emissions react with ozone and light in the atmosphere to form NO_2, the regulated air contaminant. An Applicant may predict NO_2 ambient impacts by the simple assumption that all the NO_X emissions of the source converts to NO_2 before the plume reaches the ambient air boundary. However, the modeling of ambient NO_2 concentrations can sometimes be refined by the use of ambient air data or assumptions. As of 1995, the preferred approach in EPA's *Guideline on Air Quality Models*, is the Ambient Ratio Method (ARM). The ARM analysis assumes that the modeled NO_2-to-NO_X ratio is equal to the existing ambient NO_2-to-NO_X ratio. Applicants may use a national default NO_2-to-NO_X ambient ratio of 0.75, or may use monitored data to determine an alternative ratio for their local area.

NEC used the national default NO_2-to-NO_X ratio of 0.75 to refine their predicted NO_2 ambient model values for both the standards and increment demonstrations. This is an acceptable approach.

Ambient SO_2 Modeling

The maximum modeled SO_2 ambient air quality change since the SO_2 baseline date (October 26, 1979) was compared to the three averaging periods (annual, 24-hour, and 3-hour) for the NAAQS and the PSD SO_2 increment. The NAAQS compliance demonstration was completed by adding representative ambient background data to the modeled impacts from the proposed modification at the facility and all nearby major point sources in the source inventory. The modeled SO_2 ambient air impacts were based on a fuel sulfur content to not exceed 0.5% by weight.

Off-Site Inventory

For an ambient air quality compliance demonstration, the new or modified source's impacts must be added to the impacts from existing sources and the "background" concentration that would occur without any local sources. The Dragnet and Peter Pan Seafood facility are the only notable off-site point source emission sources in the Dillingham area, or within 50 km of Dillingham. As was previously noted, the Department is aware of significant area sources, home heating sources, and commercial fishing vessel sources in the Dillingham area. Based on this finding, the Department has chosen to account for these sources by substituting a more representative ambient air data value from a monitoring station in a similar environment. The modeling analysis consisted of NEC, Dragnet, and Peter Pan point source emission sources. The representative ambient background concentration used in the modeling analysis is discussed in Section 5.3.1.

5.4.3 Department's Assessment

Most of the Department's comments regarding the ambient modeling analysis have been made in the pertinent subsections above. Independent computer runs conducted by the Department did not find significant differences in results presented in the NEC permit application. Except for the noted ambient background value change for NO_2, the results presented in Table(s) 5.4-1 and 5.4-2 reflect tables in the NEC application.

5.4.4 Final Results – AAAQS Analysis

The maximum modeled NO_2 and SO_2 ambient impact values associated with the proposed modification are shown in Table 5.4-1. The background concentrations, total impacts, and ambient air quality standards are also shown.

Table 5.4-1: AAAQS Analysis

Pollutant	Avg. Period	Maximum Modeled Conc. ($\mu g/m^3$)	Bkgd. Conc. ($\mu g/m^3$)	TOTAL IMPACT: Max Conc. plus Bkgd. ($\mu g/m^3$)	Ambient Standard ($\mu g/m^3$)
NO_2	Annual	40[1] 32[2]	18.6[1] 18.6[2]	**58.6[1]** **50.6[2]**	**100**
SO_2	3-hour	238[1] 264[2]	44 44	**282[1]** **308[2]**	**1300**
	24-hour	148[1] 164[2]	26 26	**174[1]** **190[2]**	**365**
	Annual	8[1] 8[2]	5 5	**13[1]** **13[2]**	**80**

Notes: (1) Configuration 1 is after Source 11 is installed.
(2) Configuration 2 is after Sources 12 and 13 are installed.
All NO_2 modeled concentrations are adjusted using the 0.75 ARM Value.

As shown in Tables 5.4-1 the maximum predicted NO_2 and SO_2 concentrations are below the ambient air quality standards. All of the maximum concentrations occur about 100 meters to the south and southeast of the power plant. It is also important to note that since ambient concentrations vary with distance from each source, the maximum values shown represent the highest value that may occur somewhere in the Dillingham air-shed. They do ***not*** represent the highest concentration that could occur at *all* locations in the area.

The maximum predicted NO_2 impacts are slightly greater than fifty (50%) percent of the NO_2 ambient air quality standard (58.6% and 50.6%), and less than fifty percent (50%) for the other regulated pollutants in the table. Based on the assumptions and proposed permit conditions, the Department believes the analysis represents a likely worst-case scenario, and therefore will not require NEC to conduct post-construction monitoring.

The maximum modeled annual average SO_2 ambient value was predicted to be 8 $\mu g/m^3$ at a location approximately 100 meters south of the modified facility. When this value is added to the background value assumed in Table 5.4-1, the total ambient concentration is 13 $\mu g/m^3$. The highest, second-highest modeled 24-hour average SO_2 ambient value was 164 $\mu g/m^3$ at a nearby receptor on the southern NEC power plant boundary. When modeled value is added to the assumed background value in Table 5.4-1, the total ambient concentration is 190 $\mu g/m^3$. The highest, second-highest modeled 3-hour average SO_2 ambient value was 264 $\mu g/m^3$ at a receptor 100 meters south of the NEC power plant. Adding this value to the background value assumed in Table 5.4-1 results in a total ambient concentration of 308 $\mu g/m^3$. All three modeled averaging periods are below the NAAQS for SO_2.

5.4.5 Final Results - PSD Increment Analysis

The maximum predicted NO_2 and SO_2 increment concentrations associated with operating Sources 11, 12, and 13 are summarized below in Table 5.4-2. The State's Class II PSD standards are also shown. As shown in Table 5.4-2, the maximum predicted NO_2 and SO_2 concentrations were located reasonably close and south of the facility and are within the Class II increment standards. The maximum modeled NO_2 air quality change since the NO_2 baseline date (February 8, 1988) was compared to the PSD increment of 25 $\mu g/m^3$ to determine compliance. The maximum modeled NO_2 increment at an ambient air receptor location approximately 500 meters southeast of the NEC power plant was 5 $\mu g/m^3$. This is significantly below the annual average NO_2 PSD Class II increment.

The highest, second-highest modeled 24-hour average SO_2 increment value was predicted to be 89 $\mu g/m^3$ at a receptor location 100 meters south of the NEC power plant. This predicted concentration for the 24-hour short-term SO_2 increment is over ninety-five percent (95%) of the increment. The demonstration of compliance with the SO_2 increment is based on the highest, second-high concentrations for all seven years of meteorological data. This large database adds confidence that a likely worst-case assessment has been conducted. The creation of an accurate inventory of increment-consuming sources prevents ambient monitoring for increment compliance under standard monitoring protocol and EPA monitoring guidelines. Therefore, ambient monitoring for short-term SO_2 increment will not be a condition of this permit. However, the Department reserves the right to require future ambient monitoring for short-term SO_2 levels due to field observations of pollutant effects, public complaints on the operations of the NEC facility, or other findings listed in 18 AAC 50.201.

Table 5.4-2: PSD Increment Analysis

Pollutant	Averaging Period	Maximum Modeled Concentration (□g/m³)	Class II Increment Standard (□g/m³)
NO_2	Annual	5[1] 4[2]	**25**
SO_2	3-hour	159[1] 204[2]	**512**
	24-hour	77[1] 89[2]	**91**
	Annual	2[1] 3[2]	**20**

Notes: (1) Configuration 1 is after Source 11 is installed.
(2) Configuration 2 is after Sources 12 and 13 are installed.
All NO_2 concentrations are adjusted by the default ARM factor of 0.75.

5.5 MODELING CONCLUSIONS

NEC has shown that the emissions associated with the proposed Dillingham Power Plant project will not cause or contribute to violations of the ambient air quality standards provided in 18 AAC 50.010, or the increments provided in 18 AAC 50.020(b)(2). The Department finds that NEC has fulfilled the showing requirements under 18 AAC 50.315(e)(3)(B).

The Department has developed conditions in Section 2 of the construction permit to ensure compliance with ambient air quality standards and increments. The most notable conditions are summarized below.

1. The Department is limiting the maximum distillate fuel sulfur content to 0.50% by weight to protect 3-hour and 24-hour SO_2 increments and standards.

2. The Department is requiring NEC to construct and operate the facility in accordance with the application and subsequent submittals. NEC must locate and build the engine exhaust stacks according to the design parameters used in the modeling analysis to ensure compliance with the applicable AAQS and standards. Permit Condition 11 allows for changes subject to Department review and approval.

3. The Department is limiting annual power generation of the Configuration 1 engine generators (Sources No. 3, 5, 6, 8, 9, 10, and 11) and the Configuration 2 engine generators (Sources No. 3, 5, 6, 10, 11, 12, and 13) to the values listed in Table 8-1 of the application to protect annual increments and standards for SO_2 and NO_2. The annual generation caps seem overly conservative; however, the Department has no demonstration that operation above these levels will comply with the standards and increments.

6.0 AIR QUALITY-RELATED VALUES AND ADDITIONAL IMPACTS

NEC submitted an analysis of the impact from the proposed project and associated growth on air quality-related values as required under 18 AAC 50.310(d)(4). This section summarizes the Department's assessment of these impacts.

6.1 PRIMARY IMPACTS

Air quality impacts on visibility, soils, vegetation, noise, and odor due to the proposed project are considered "primary impacts." The maximum ambient concentrations predicted from operation of the facility have been used for this assessment. These potential impacts are described below.

6.1.1 Visibility

PSD applicants must assess whether the emissions from their facility, including associated growth, will impair visibility. Visibility impairment means any humanly perceptible change in visibility (visual range, contrast, or coloration) from that which would have existed under natural conditions (40 CFR 51.301(x)). The pollutants that can impair visibility are NO_X, SO_2, and

PM-10. NO_X emissions can form a reddish-brown plume, sulfates formed from SO_2 can absorb light, and particulate matter, such as sulfates and nitrates, can scatter light. Visibility impacts can be in the form of visible plumes ("plume blight"), or in a general, area-wide reduction in visibility ("regional haze").

Visibility is an important air quality-related value for the Class I areas of Alaska. Therefore, applicants must assess the potential plume blight impact in any Class I area located within 100 kilometers (km) of their facility. The procedures for conducting a visibility impact analysis are contained in EPA's *Workbook for Plume Visual Impact Screening and Analysis - Revised* (EPA 1992). At the discretion of the Department or as requested by a Federal Land Manager, PSD applicants may be required to evaluate Class I visibility impacts, even if the proposed project is outside of this 100 km radius. The same approach is used for the two "integral vistas" within Denali National Park and Preserve. These vistas are the Mt. Deborah and Mt. McKinley Wonder Lake areas defined in 18 AAC 50.025. These vistas are views of distant geographic features of unique importance to visitors' enjoyment of the park.

Alaska does not have plume blight standards for Class I or Class II areas. For Class I areas, the Federal Land Manager provides the desired values. The Federal Land Manager requires that the 24-hour average visibility reduction associated with the project be less than 5% of background, which is estimated to be 250 km for the area of concern. There are no established criteria for Class II areas. Therefore, Class II impact results are compared to the typical Class I criteria.

The nearest Class I area, the Tuxedni National Wildlife Refuge, is located about 350 km east-northeast of Dillingham. Therefore, the NO_X, SO_2, and PM-10 emissions from the Dillingham Power Plant should have no perceptible effect on the visibility within this or any other Alaskan Class I areas. NEC verified that no plume visibility will occur from the proposed modification by using EPA's VISCREEN computer model (version 1.01, dated 88341). The EPA Visibility Workbook recommends the use of a Delta E value of 2 (Latimer and Ireson 1992). Thus, a Delta E of 2 and a contrast of 2 percent give approximately the same theoretical value for an NO_2 burden just large enough to cause perceptible effects. The Theoretical perceptibility threshold of 2 percent contrast derived from the model, or 69 ppbv*km, is used in the analyses for the proposed modification. Assuming a background visual range of 250 km, the worst-case visibility impact from the Dillingham Power Plant was assessed according to the guideline visibility workbook. The screening calculations resulted in visual impact estimates that did not exceed the screening criteria. The maximum visual impacts inside the Class I area were estimated to be about 1 percent of the criteria (Appendix G; Delta E value of 0.019), and the impacts outside of the Class I area were also about 1 percent of the screening criteria.

The applicant is also required under PSD regulations to demonstrate that the facility emissions will not cause an impairment to the Class I area once they have become sufficiently diluted and mixed so they are no longer an identifiable plume (regional haze). In general, regional haze is caused by multiple sources located within the region, and a single emission source may contribute, but is not the sole contributor to regional haze. Regional haze is characterized by a decrease in visual range and in the contrast of observed landscape features (Mt. Deborah, Mt. McKinley). Diluted NO_X emissions have negligible visible effect, and their oxidation product is nitric acid, which is an invisible gas. The assumed 250 km background visual range value is from measured data for an interior monitoring site that has little to no influence from a marine environment such as that found around Dillingham. Therefore, if the Federal Land Manager proposed a background visual range that is more representative of salt spray and humidity effects, this may lower the expected visual range of this area. The resulting modeled value of the visibility impact would be even smaller due to the limited visual range in a marine environment.

NEC also stated that the Dillingham Power Plant engines normally have non-visible exhaust plumes, and rarely exceed 10% opacity. The Department has no record of public complaints on visible plume emissions from the operation of the NEC facility.

6.1.2 Soils

Major soil factors are dependent on moisture, geologic parent material, organic residue, topographic relief, climate, vegetation, and permafrost. Soils in the Dillingham area vary from young, immature soils to older, well-developed soils. Dillingham sits on a low point of land between two rivers. The higher land within town is organic filled-gravel, while the lower areas are peat, moist tundra, and bogs. The major soil-forming factors determining the soils developed on the landscape are moisture, geologic parent material, organic residue, topographic micro-relief, climate, and vegetation. All soils have been (or are being) developed under a relatively harsh environment. Furthermore, much of the annual precipitation falls during soil development periods. Although moisture is required for optimum soil-forming activities, the rain is cool, keeping the soil temperature low even on warmer summer days.

Soils act as an effective sink for gaseous pollutants, such as NO_X. The rate of soil absorption is dependent on distance from the source, soil properties, cover vegetation, and meteorological conditions. NEC used a screening equation developed by the U.S. Fish and Wildlife Service (USFWS 1978, Smith and Levenson 1980) to estimate the amount of potential deposition due to the Dillingham Power Plant. The annual deposition of NO_X is 10 $\mu g/m^3$. NEC stated that this value is negligible and would not change the fertility level of most soils formed on the landscape near Dillingham. Based on this information, the Department does not expect any adverse impacts on soils from the proposed project.

6.1.3 Vegetation

The vegetation around Dillingham consists largely of moist tundra, wet tundra, closed spruce-hardwood forests, and alpine tundra. Moist and wet tundra near Dillingham and surrounding areas occupy poorly drained areas, often interspersed with standing water or dense growth of mosses. The closed spruce-hardwood forests in the higher terrain to the north and west of Dillingham yield to alpine tundra at higher elevations. Within the moist and wet tundra, cotton grass tussock growth is continuous and uniform. Mosses and lichens grow in the more open channels. Shrubs consist of dwarf birch, willows, and Labrador tea. The factors that could influence the toxic response of a plant to a given pollutant are: biological characteristics of the plants, environment, pollutant concentrations, and duration of exposure.

The Department compared the maximum predicted concentrations from the modification to the NO_2 vegetation exposure screening thresholds published by EPA (EPA 1980).[9] The comparison is summarized below in Table 6.1-1. The comparison includes background concentrations. The maximum predicted concentration is well below the vegetation screening thresholds. Although the proposed level of increase of SO_2 emissions are less than the significant threshold value, it can be seen in results presented in Table 6.1-1 that maximum modeled values for this pollutant will be significantly less than reported sensitivity threshold values.

Table 6.1-1: Phase 3 Ambient Impacts and Vegetation Sensitivity Thresholds

Pollutant	Averaging Time	Maximum Modeled Impact (□g/m^3)	Minimum Reported Vegetation Sensitivity Threshold Values (□g/m^3)		
			Sensitive	Intermediate	Resistant
NO_2	Annual	46	94-188	94-188	94-188
SO_2	3 hours	229	786	2,096	13,100
	Annual	12	18	18	18

Lichens

Department regulations require an air quality related values analysis listed in 18AAC 50.310(d), be limited to pollutants with an emissions increase greater than or equal to the values listed in 18 AAC 50.300(h)(3). For the NEC modification, this analysis only applies to NO_X emissions and not SO_2. However, the Department is aware of studies of Alaskan lichens that may be similar to those found near the NEC power plant. Based on this information, the Department has developed the following:

A significant type of vegetation found in Alaska which is sensitive to air pollution is lichens. Some lichens are known to have a lower SO_2 and trace metal thresholds than vascular plants. They also bio-accumulate these pollutants. Lichens are divided into three different morphological growth types: fruticose, crustose, and foliose.

The impact of chronic exposure to SO_2 has been studied by the U.S. Forest Service on several lichen species found in the Tongass National Forest in southeast Alaska (Geiser 1994). They found that lichens vary in sensitivity to chronic SO_2 exposures. The most sensitive species may incur damage at an annual average concentration of 13 □g/m^3, while the more tolerant species can thrive with annual average concentrations exceeding 100 □g/m^3. Studies of lichens in the Pacific Northwest have also found that the most sensitive varieties may incur damage at an annual average concentration of 13 □g/m^3 (DOA 1992).

[9] EPA did not provide thresholds for particulate matter in their 1980 report.

While the lichens found in the Tongass National Forest and the Pacific Northwest may not exist in Dillingham, the 13 □g/m^3 sensitivity threshold value may indicate the potential sensitivity for local lichens. It is unknown if and how annual snow pack impacts the sensitivity levels. However, this value is a potential indicator.

As shown in Table 5.4-1, the maximum annual average SO_2 concentration from normal operation is 12 ug/m^3 (including the background concentration). This is slightly below the lowest sensitivity threshold found by the U.S. Forest Service. Although, the Department does not expect long-term lichen damage due to emissions from the Dillingham Power Plant. The Department will reserve a final conclusion as no site-specific data has been developed for lichens in the Dillingham area.

6.1.4 Noise

NEC is an existing power plant with 24-hour operations of several internal combustion engine generators. The Department does not expect an increase in outside noise as a result of the proposed modifications. Therefore, unless public complaints document otherwise, the Department does not expect adverse noise effects from the proposed project to install replacement generators.

6.1.5 Odors

The proposed modification to the NEC power plant will include taller stacks for the engine generating units. These taller stacks should provide better dispersion of odor-causing elements in the diesel exhaust gases. Unless public complaints document otherwise, the Department does not expect any odor problems from the proposed project to install replacement generators with taller exhaust stacks.

6.2 SECONDARY IMPACTS

Secondary impacts are those air quality impacts caused indirectly by the proposed project. Induced social and economic growth and increased air, land, and water traffic impacts are evaluated as part of PSD pre-construction review.

The project is in response to growth in community power needs and the Department does not consider the modification to be a cause of growth in the Dillingham area. NEC is adding generation capacity in response to an increased electrical demand, and to ensure that reliable power is available during peak loads. NEC does not expect additional commercial, residential, or industrial emissions as a result of this project. NEC plans to use the current staff level to operate and maintain the proposed equipment. Therefore, the Department does not expect adverse secondary impacts resulting from this project.

7.0 PERMIT ADMINISTRATION

The Department has prepared Air Quality Control Construction Permit 0025-AC003 for the Nushagak Electric Cooperative, Inc., Dillingham Power Plant Project. The Permit authorizes NEC to operate the proposed emission sources in accordance with 18 AAC 50.315 and AS 46.14.170.

7.1 PERMIT CONDITIONS

All facilities permitted under the Air Quality Control Rules are under the purview of the Department's Air Permits Program. The Section's Inspection Service Group has oversight for all reports, surveillance, records, and inspections of permitted facilities. Therefore, all plans, reports, and notices required under this permit should be submitted to the Group's Fairbanks Office, as provided for in Section 9, Condition 38, of the Construction Permit.

The Department incorporated:

- Standard Permit Conditions listed in 18 AAC 50.345(a) as Section 1, Conditions 1 through 8 of the Construction Permit.
- Section 2 includes conditions to restrict operations and fuel properties in order for the project to comply with ambient standards and increments.
- Section 3 includes provisions to avoid prevention of signification deterioration classification for CO and SO_2.
- Section 4 incorporates BACT emission limits, with monitoring, record keeping, and reporting requirements for NO_X.
- Sections 5 and 6 incorporate applicable federal emission standards by reference.
- Section 7 incorporates State emission standards for fuel burning equipment, and industrial processes, open burning, and air pollution prohibitions. The Section also includes monitoring, record keeping, and reporting requirements for each section. Finally, this Section includes a permit term for good air pollution control practices.
- Section 8 lists general source testing and monitoring requirements for this permit.
- Record keeping and reporting obligations are listed in Section 9.
- Section 10 lists the source inventory for the Dillingham Power Plant Facility.
- Section 11 contains the permit application documentation that NEC has provided for the project.
- Section 12 includes an Excess Emission Notification Form for NEC to report operations and emission deviations from the permit terms.
- Section 13 lists Visible Emission Evaluation Procedures.
- Section 14 contains the Quarterly Facility Operating Report.

7.2 PROJECT CONSISTENCY WITH ACMP

The Dillingham Power Plant is located in the Bristol Bay Borough's Coastal District, and therefore is subject to consistency review with the Alaska Coastal Management Program (ACMP). The applicant submitted a coastal project questionnaire in the January 1999 PSD construction permit application (see Appendix C). The questionnaire identifies the need for NEC to apply for an Air Quality Control Permit. Therefore, under 6 AAC 50.030, the Department of Environmental Conservation is conducting a sole-agency review of NEC's proposal for project consistency under the ACMP.

The Department proposes terms and conditions for facility compliance with the Alaska Air Quality Control Regulations, 18 AAC 50, and the Federal Clean Air Act pre-construction review prevention of significant deterioration program as delegated to the State of Alaska. 18 AAC 50, effective August 18, 1992, is incorporated by reference within the Alaska Coastal Management Program, 6 AAC 80.140.

8.0 FINAL DECISION

NEC's application and follow-up documents for a construction permit satisfy the requirements in 18 AAC 50.310. Their application demonstrates that the facility will meet the applicable requirements set out in 18 AAC 50.315(e). Therefore, in accordance with 18 AAC 50.315(b), the Department has made a decision to issue a construction permit to NEC for the Dillingham Power Plant. Also, in accordance with 18 AAC 50.315(c), the Department has public notices published in the Bristol Bay Times and posted in the local post office soliciting public comments regarding the preliminary permit decision. Copies of the preliminary decision were available for review at the Department's Juneau and Anchorage Air Permits Offices and the Dillingham Public Library in Dillingham, Alaska.

4.3 The terms and conditions of the permit do not preclude any action by the State, EPA, or the Federal Land Manager to mitigate any material violation of the permit, or the mitigation of any secondary effect from the emissions of the facility.

4.4

The Department made its decision to issue the construction permit after consideration of comments received during the public comment period.

9.0 REFERENCES

18 AAC 50. Air Quality Control Regulations. Alaska Department of Environmental Conservation. June 21, 1998.

41 CFR Part 51 Appendix W. *Guideline on Air Quality Models (Revised).* August 1996.

40 CFR Part 60. Standards of Performance for New Stationary Sources. July 1996.

DOA 1992. *Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest.* U.S. Department of Agriculture; Forest Service; Pacific Northwest Research Section; General Technical Report PNW-GTR-299. May.

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Appendix A: Emissions Information

Appendix B: NO_X BACT Analysis

BACT Analysis for Nitrogen Dioxide
Nushagak Electric Cooperative, Inc. – Dillingham Power Plant

TABLE 1: NO_X BACT ASSESSMENT - SOURCES NO. 11, 12, 13

Option 1 = Selective Catalytic Reduction with the Lean-Burn/Low NOx Package
Option 2 = Selective Catalytic Reduction
Option 3 = Lean-Burn/Low NOx Package
Option 4 = Base Case

PARAMETER	OPTION 1	OPTION 2	OPTION 3	OPTION 4
Capital Cost	$ 602,647.0	$ 552,647.0	$ 50,000.0	$ -
Operating Cost Per Year	$ 148,856.3	$ 140,493.4	$ 24,371.2	$ -
Total Annualized Cost	$ 234,432.2	$ 218,969.3	$ 31,471.2	$ -
Full Load Emission Rate (tpy)	21.8	34.9	109.0	174.6
Assumed Emission Rate (tpy)	16.9	27.1	84.6	135.6
Percent NOx Reduction	87.5%	80.0%	37.6%	0.0%
NOx Removed (tpy)	118.6	108.4	54.9	0.0
Cost Per Ton Removed	$ 1,976.1	$ 2,019.1	$ 619.9	$ -
ENGINE SPECIFIC - Equip 1 unit with control and compare to engine's operating costs and power generation				
Engine Projected ekWh per year	7,140,000	7,140,000	7,140,000	
Control Cost Per ekWh Increase	$ 0.03119	$ 0.02476	$ 0.00356	$ -
Projected Cost per ekWh	$ 0.14687	$ 0.14044	$ 0.11924	
Percent Increase per ekWh	27.0%	21.4%	3.1%	0.0%
FACILITY SPECIFIC - Equip 3 units with controls and compare to facility's operating costs and power generation				
Total Projected ekWh per year	26,000,000	26,000,000	26,000,000	
Controls Cost Per ekWh Increase	$ 0.02705	$ 0.02527	$ 0.00363	$ -
Total Projected Cost per ekWh	$ 0.14273	$ 0.14095	$ 0.11931	$ -
Total Percent Increase per ekWh	23.4%	21.8%	3.1%	

Notes:

(1) To get an accurate analysis of projected operation, costs and emission rates assume engines run at 8000 hrs/yr and 85% load. However, the permit restricts these engines to 7,000,000 ekWh/yr, approx. 8032 hrs and 83% load to avoid PSD for other pollutants and protect ambient air quality standards and increments.
(2) No data is available for an individual engine cost per ekWh. Therefore, unit specific costs of power production are compared with facility average costs.
(3) See following pages for calculations and explanations of the BACT analysis.

1998 Actual Data Used:

Cost of Electrical Power Generation at NEC, 1998:	$2,089,647
Total ekWh Generated by NEC in 1998:	18,064,000
Number of Rate Payers in 1998:	1,374
Facility Cost Per ekWh Produced, 1998:	$0.1157

BACT Analysis for Nitrogen Dioxide
Nushagak Electric Cooperative, Inc. – Dillingham Power Plant

Two documents were used in this BACT analysis: (1) a 4 page cost estimate submitted April 11, 1999 by the applicant; and (2) vendor specifications for the Caterpillar 3512B diesel engine provided in the January 1999 application (and updated in the Preliminary Permit Comments). The cost estimate document can be seen following this analysis. The vendor specification document can be seen in Appendix A.

The Department's analysis differs slightly from the applicant's as explained below. Both analyses used projected actuals to get an accurate cost estimate, 85% load and 8000 hours of operation. To avoid PSD for other pollutants and protect the standards and increments, the permit restricts operation to 7,000,000 ekWh per year, approximately 83% load and 8032 hours of operation. Note: the numbers below may be slightly off due to rounding.

Option 4: Base Case

The base case is a standard mechanically injected 1,050 Caterpillar #3512 Diesel Engine. The applicant assumed that NOx emissions were similar to the low brake specific fuel consumption strategy of the Caterpillar #3512B Engine.

NOx Emissions at full load = 39.87 lb/hr @ 1476 bhp (vendor information, see Appendix A)
Fuel Consumption = 68.2 gal/hr (vendor information, see Appendix A)
Fuel Consumption = 68.2 gal/hr * 7.07 lb/gal / 1476 bhp = 0.3267 lb/bhp-hr (**applicant stated 0.338 lb/bhp-hr, see following pages)

NOx Emissions at 85% load = 39.87 * 0.85 = 33.89 lb/hr (**applicant stated 32.53 lb/hr, see following pages)
NOx Emissions at 85% load and 8000 hours = 33.89 lb/hr * 8000 hr / 2000 lb = 135.56 tpy

Option 3: Lean-Burn/Low NOx Package

NOx Emissions at full load = 24.89 lb/hr @ 1476 bhp (updated vendor information (was 24.2 lb/hr), see Appendix A)
Fuel Consumption = 209 g/bkW-hr (vendor information, see Appendix A)
Fuel Consumption = 209 g/bkW-hr * 1 lb/453.6 g * 0.7457 bkW/bhp = 0.3436 lb/bhp-hr (**applicant stated 0.335 lb/bhp-hr, see following pages)

NOx Emissions at 85% load = 24.89 * 0.85 = 21.16 lb/hr (**applicant stated 20.48 lb/hr, see following pages)
NOx Emissions at 85% load and 8000 hours = 21.16 lb/hr * 8000 hr / 2000 lb = 84.6 tpy

NOx Reduction from Base Case = 135.56 – 84.6 = 50.93 tpy
Percent NOx Reduction = 50.93 / 135.6 * 100 = 37.6%

Capital Cost = $50,000 (applicant information, see following pages)
Annual Maintenance Cost = $5,000 (applicant information, see following pages)
Additional Fuel Needed = (0.3436 lb/bhp-hr – 0.3267 lb/bhp-hr) * 1476 bhp * 0.85 * 8000 hr / 7 lb/gal = 24,214 gallons (**applicant stated 4,320 gallons, see following pages)
Annual Fuel Cost Increase = 24,214 gal * $0.8 / gallon = $19,371 (**applicant stated $3,456, see

following pages)

Total Capital Cost = $50,000
Total Annual Operating Cost = $24,371

Total Annualized Cost @ 7% interest and 10 year amortization = ($50,000 * 0.142) + $24,371 = $31,471/yr (**applicant stated $14,192, see following pages)

Cost per Ton NOx Removed = $31,471 / 50.93 tpy = $619.9

Option 2: Selective Catalytic Reduction

The applicant's cost assessment for SCR assumed controls on only two engines, stating these controls were infeasible on the third engine due to space constraints. Because the applicant did not present any material to backup this claim, the Department asserts that the assessment should provide costs for all 3 engines. Therefore, the Department assumed that the SCR cost of the third engine would equal the cost of controls on the first two even though more costs could arise to eliminate the space constraint issue.

Percent NOx Reduction = 80.0%
NOx Reduction from Base Case = 135.6 * 0.8 = 108.48 tpy

Capital Cost for SCR Housing = $339,897 (applicant information, see following pages)
Capital Cost for Construction = $212,750 (applicant information, see following pages)
Annual Maintenance Expense = $36,655 (applicant information, see following pages)
Annual Loss of Heat Recovery = $50,400 (applicant information, see following pages)
Annual Freight Costs for Filter Replacement = $200 (applicant information, see following pages)
Annual Urea Costs = $0.265/lb
Annual Storage Costs at 7% interest and 10 year amortization = ($150,000 * 0.142) / (108.48 tpy * 2000 lb / 1.35 * 2) = $0.0663 (**applicant stated $0.089, see following pages)
Annual Storage and Urea Costs = (0.265 + 0.0663) * 108.48 tpy * 2000 lb / 1.35 = $53,238.4 (**applicant stated $34,329, see following pages)
Annual Operating Cost for Low NOx = $24,371

Total Capital Cost = $552,647.0
Total Annual Operating Cost = $140,493.4

Total Annualized Cost @ 7% interest and 10 year amortization = ($552,647 * 0.142) + $140,493.4 = $218,969.3/yr (**applicant stated $184,961, see following pages)

Cost per Ton of NOx Removed = $218,969.3 / 108.48 tpy = $2019

Option 1: Selective Catalytic Reduction w/ a Lean-Burn/Low NOx Package

Percent NOx Reduction due to Lean-Burn/Low NOx Package = 37.6%
NOx Reduction from Base Case = 135.6 * 0.376 = 50.93 tpy
NOx Emissions after Lean-Burn/Low NOx = 135.6 – 50.93 = 84.6 tpy

Percent Reduction with SCR = 80%
NOx Reduction due to SCR = 84.6 * 0.8 = 67.704 tpy

Capital Cost for Both Options = Capital Cost for SCR + Capital Cost for Lean-Burn/Low NOx Engine =

$552,647.0 + 50,000 = $602,647.0
Annual SCR Maintenance Expense = $36,655 (applicant information, see following pages)
Annual Loss of Heat Recovery = $50,400 (applicant information, see following pages)
Annual SCR Freight Costs for Filter Replacement = $200 (applicant information, see following pages)
Annual Urea Costs = $0.265/lb
Annual Storage Costs at 7% interest and 10 year amortization = ($150,000 * 0.142) / (67.704 tpy * 2000 lb / 1.35 * 2) = $0.106 (**applicant stated $0.089, see following pages)
Total Annual Storage and Urea Costs = (0.265 + 0.106) * 67.704 tpy * 2000 lb / 1.35 = $37,230.1 (**applicant stated $34,329, see following pages)

Total Capital Cost = $602,647.0
Total Annual Operating Cost for both options = $148,856.3

Total Annualized Cost @ 7% interest and 10 year amortization = ($602,647 * 0.142) + $148,856.3 = $234,432.2/yr (**applicant stated $184,961, see following pages)

Ton per Year of NOx Removed = $234,432.2 / 118.6 tpy = $1976.1

Appendix C: Coastal Project Questionnaire